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MANUAL

FOR THE

OIL AND GAS INDUSTRY

UNDER THE

REVENUE ACT OF 1918

BY

RALPH ARNOLD, J. L. DARNELL
and Others

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FOREWORD

This manual is issued to assist the taxpayer of the oil and gas industry in correctly and expeditiously preparing his Federal tax returns. Although the endeavor has been to anticipate all questions that might be asked regarding the law and regulations, and the latter have been amplified when it was deemed necessary to secure the desired result, it is recognized that any such manual is merely suggestive and can not cover all situations which may exist.

The book consists of three parts.

Part I deals directly with the law and regulations as they relate to the oil and gas industry.

Part II, dealing with the question of depreciation, is included to assist the taxpayer in standardizing his classification of equipment and to offer a suggestion as to relative rates of depreciation for different types of physical property. The rates are *not* to be applied indiscriminately to specific cases, and the Treasury Department is in no way committed to accept them in the returns.

Part III consists of descriptions of methods of estimating underground oil reserves, especially by means of production curves, and a collection of curves and tables covering many of the principal oil pools and fields in the United States. The curves and tables are intended as a *suggestion* for the guidance of the taxpayer in the computation of his depletion allowance, which in turn usually has a direct bearing on the amount of his tax. They are not to be applied indiscriminately to specific properties, and the Treasury Department is in no way committed to accept estimates based upon them. Every claim for deduction on account of depletion must be accompanied by a detailed statement of production, etc., upon which such claim is based.

These curves and tables are based upon a careful systematic study of thousands of production records; all that could be made available in the limited time at the disposal of the Bureau. Many

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refinements and minor corrections are desirable but must be delayed until more complete records are in hand. With such records it will be possible to make curves to apply to more restricted areas and thus more closely approximate the conditions which apply to individual tracts.

Usually it will be to the advantage of the producer to make estimates for each property rather than to assume that his particular property is an average. Any or all of the methods discussed may be applied by the producer to his own properties. Obviously, manner of operation, accidents, and other factors will influence the future production just as they have the past production, but experience has shown that ordinarily these are not likely to cause wide deviation from estimates which have been carefully made. Examination of production records of individual properties will show whether the probability of such occurrences will make estimates unsafe.

In cases of apparent hardship to the taxpayer it will not infrequently happen that such hardships are the direct result of failure on his part to procure sufficiently detailed records, and, lacking these, great difficulty will be encountered in establishing the facts. Such conditions may have been excusable in the past, but henceforth the responsibility rests squarely upon the taxpayer, as his claims must be supported by all necessary data bearing on the case.

The investigation resulting in the preparation of this manual was begun before the signing of the armistice, and most of the men who took part in it were called from their usual vocations and undertook the work at a financial sacrifice, and often at great personal inconvenience. The oil operators throughout the country have been most generous in their cooperation in the prosecution of the work, not only as individuals but in their organizations. The hearty support of the Bureau of Mines, Geological Survey, Fuel Administration, and other Federal bureaus has at all times been given. Without the assistance of these agencies the work could not have been finished. The Bureau is therefore greatly indebted to all for their services, and wishes to extend its thanks for their assistance.

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INTRODUCTION

This Manual was first issued by the Bureau of Internal Revenue of the Treasury Department in February, 1919, shortly after the passage of the Revenue Act of 1910. The original edition of 10,000 copies was soon exhausted, and the demand for the book has become so great that the present private reprint, bringing certain features up to date, has been decided upon.

The volume was prepared to assist the taxpayer of the oil and gas industry in correctly and expeditiously preparing his Federal tax returns.

Although the endeavor was made to anticipate all questions that might be asked regarding the law and regulations, and the latter were amplified when it was deemed necessary to obtain the desired result, it is recognized that such a manual is only general and cannot cover all cases that may exist. The Manual is based largely upon information gathered during the Fall of the year 1918 by a corps of geologists, technologists and engineers. The investigation was undertaken primarily to furnish a basis for arriving at valuations, and deleption and depreciation deductions in connection with oil and gas properties. Deeming these subjects to be of the greatest importance, the Bureau of Internal Revenue instituted a most careful inquiry. All fields in the United States were canvassed. Records of production of thousands of properties were collected and tabulated. These were carefully classified and studied by the most competent and experienced men in the country and the average future production curves and tables of valuation data were produced as a result of this study.

In compiling the Manual, the country was divided into seven districts, each of which was handled by a supervisor and several assistants. These were the

Appalachian Field.—G. B. Richardson, of the U. S. Geological Survey, assisted by Barnum Brown, L. C. Glenn, Roswell H. Johnson and others.

Lima-Indiana and Illinois Fields.—Thos. E. Savage, Supervisor, assisted by J. L. Darnell, L. G. Donnelly and others.

Mid-Continent Field.—J. O. Lewis, Supervisor, assisted by H. B. Goodrich, Calvin T. Moore, James H. Hance, W. E. Wrather and others.

Northern Louisiana Field.—A. Faison Dixon.

Gulf Coast Field.—E. DeGolyer, Supervisor, assisted by A. Faison Dixon, M. W. Mattison and others.

The Rocky Mountain District.—Cassius A. Fisher, Supervisor, assisted by Arthur Eaton, C. W. Comstock and others.

California.—Carl H. Beal, Supervisor, assisted by N. R. White, E. D. Nolan, Robert B. Moran and others.

The foreign countries including Mexico were covered by V. R. Garfias.

The natural gas industry was handled by E. W. Shaw of the U. S. Geological Survey, assisted by S. S. Wyer, A. J. Diescher, W. J. Judge, W. A. Williams, T. B. Gregory, F. R. Clark, E. H. Finch and K. D. White.

The book consists of three parts.

Part I deals directly with the Law and Regulations. These as they relate to the oil and gas industry, are explained and numerous illustrations and examples are given to bring out their application. Since the issuance of the original edition of the Manual the regulations relating to discovery, proven tract or lease, property disproportionate in value and proof of discovery (Art. 220*a* and 221) have been altered by the adoption of Treasury Decision 2956 (December 2, 1919.) The new regulations regarding these subjects are printed on pp. 44 to 46.

Part II deals with the question of depreciation and is the result of the work of a committee of which W. A. Williams, of the Fuel Administration, was chairman, assisted by Thos. Cox, A. W. Ambrose, H. H. Hill, J. P. Smoots of the Bureau of Mines and L. G. Donnelly of the Bureau of Internal Revenue. This chapter should assist the taxpayer in standardizing his classification of equipment. It also offers suggestions as to relative rates of depreciation for different types of physical property. The rates are not to be applied indiscriminately to specific cases

but are relative only and the Treasury Department is in no way committed to accept them in the returns.

Part III consists of descriptions and methods of estimating underground oil reserves, especially by means of productive curves. The principal paper in this chapter is by J. O. Lewis and C. H. Beal of the United States Bureau of Mines, whose work along this same line is well known to petroleum engineers throughout the country. A collection of curves and tables covering many of the oil fields and pools in the United States accompanies the text. In the case of the individual districts, these curves and tables were prepared under the supervision of the men in charge of the districts in which the pools and fields are situated. The curves and tables relating to the Gulf Coast fields were not included in the original Manual; the tables were issued subsequently in pamphlet form; the curves have been prepared from the tables especially for this present edition.

The curves and tables are intended as a suggestion for the guidance of the taxpayer in the computation of his depletion allowance, which in turn has a direct bearing on the amount of his tax. They are not to be applied indiscriminately to specific properties, and the Treasury Department is in no way committed to accept estimates based upon them. Every claim for deduction on account of depletion must be accompanied by a detailed statement of production, etc., upon which such claim is based. One of the principal reasons for reprinting the Manual was the desire to continue the availability of the curves and tables which have so many other uses besides that of forming a basis for tax computations. Among these uses might be mentioned appraisal work on properties and fields, estimation of life of properties and fields, comparative study of the productivity and rate of decline of fields, etc.

The curves and tables are based upon a careful systematic study of thousands of production records; all that could be made available in the limited time at the disposal of the Bureau. Many refinements and minor corrections are desirable, but must be delayed until more complete records are in hand.

The work of compiling and editing the material in the manual was done largely by A. D. Brokaw, J. L. Darnell and L. G. Donnelly. The investigations leading to the preparation of the manual and its compilation and publication were under the general

supervision of the writer, then Chief of the Oil and Gas Section.

Following the resignation of the writer, J. L. Darnell was made Chief of the Natural Resources Branch of the Internal Revenue (including Oil and Gas), he holding the position until March 1, 1920, when he was succeeded by J. C. Dick. Those taking part in the collection and compilation of the material on which the Manual is based, in addition to those already mentioned are:

California Field: Carl H. Beal. Blackmar, C. A., Hall, L. S.; Johnson, H. R.; Moran, R. B.; Nolan, E. D.; Gibson, E. J.; Arrell, D. B.; White, N. R.; Kingsberry, J. W.; Boyd, H.; Clute, W. S.; Campbell, Harry; Trengrove, S. R.

Rocky Mountain Field: C. A. Fisher. Lewis, J. W.; Patton, H. B.; Eaton, Arthur; Prommel, H. W.; Comstock, Chas. W.; Prather, R. C.; Olds, Thos. H.

Mid-Continent Field: J. O. Lewis. Richards, Ralph; Sampson, C. E.; Hance, J. H.; Wrather, W. E.; Hammer, A. A.; Lloyd, E. R., U. S. G. S.; Goodrich, H. B.; Taylor, C. H.; Moore, C. T.; McKnight, R. J.; St. Clair, Stuart; Blisingame, Wade A.; Caudill, S. J.

Gulf Field: E. DeGolyer and A. F. Dixon. Hopkins, O. B.; Mattison, M. W.; Prather, W. W.; Garfias, V. R.; Springer, A. R.; Bentley, W. T.; Kupferstein, J. T.

Illinois and Lima-Indiana; T. E. Savage. Donnelly, L. G.; McConnell, K.; Darnell, J. L.; Henney, T. V.; Franklin, Louis; Lines, E. F.; Dawson, Dan; Barrett, Edw.; Blatchley, R. S.; Kahn, J. B.; White, K. D.; Morgan, D. M.; Herald, F. A.; Campbell, R. M.; Welsh, LeRoy G.; Rasmus, Walter; Cox, Eugene G.; Eskil, Rolf M.; Pengilly, H. E.; Duval, Wm. C.

Appalachian Field: Geo. B. Richardson. Glenn, L. C.; Stout, W.; Ports, P. L.; Brown, Barnum; Hoeing, J. B.; Melcher, A. F.; Miller, A. M.; McElroy, S. M.; Johnson, R. S. H.; Miller, M. M.; Johnson, F. Arthur; Herzig, J. A., Rev. Agt.; Bender, W. J., Rev. Agt.; Bernard, G. A., Rev. Agt.; Jillson, M. R.; Stephenson, E. A.

Gas Fields: E. W. Shaw. Clark, F. R.; Moore, R. C.; Wrather, W. E.; Lee, W. T.; Patton, H. B.; Finch, E. H.

MANUAL FOR THE OIL AND GAS INDUSTRY

PART I.

AMPLIFICATION OF THE LAW AND REGULATIONS.

KINDS OF TAXES IMPOSED.

The Revenue Act of 1918 levies the following taxes upon the net incomes received by individuals and corporations during the taxable year 1918:

Normal income tax.—Section 210 of the Revenue Act of 1918 levies upon the net income of every *individual, a normal tax* at the following rates:

For the calendar year 1918, 12 per cent of the amount of the net income in excess of the credits provided in section 216: *Provided,* That in the case of a citizen or resident of the United States the rate upon the first $4,000 of such excess amount shall be 6 per cent.

Surtax.—In addition to the normal tax a surtax is imposed at the rates specified in the statute upon the net income of every individual, resident or nonresident. In determining the taxable net income for the purpose of the surtax, the credits provided by section 216 of the statute in the case of the normal tax are not applicable.

Computation of surtax.—The following table shows the surtax on net incomes of the specified amounts. In each instance the first figure of net income in the net-income column of the table is to be excluded and the second figure included. The percentage given opposite applies to the excess of income over the first figure in the net-income column, and the sum in the next column is the tax on the entire difference between the first figure and the second figure in the net-income column. The final column gives the total surtax on a net income equal to the second figure in the net-income

Net Income.	Per Cent.	Surtax.	Total Surtax.
$5,000 to $6,000	1	$10	$10
$6,000 to $8,000	2	40	0
$8,000 to $10,000	3	60	110
$10,000 to $12,000	4	80	190
$12,000 to $14,000	5	100	290
$14,000 to $16,000	6	120	410
$16,000 to $18,000	7	140	550
$18,000 to $20,000	8	160	710
$20,000 to $22,000	9	180	890
$22,000 to $24,000	10	200	1,090
$24,000 to $26,000	11	220	1,310
$26,000 to $28,000	12	240	1,550
$28,000 to $30,000	13	260	1,810
$30,000 to $32,000	14	280	2,090
$32,000 to $34,000	15	300	2,390
$34,000 to $36,000	16	320	2,710
$36,000 to $38,000	17	340	3,050
$38,000 to $40,000	18	360	3,410
$40,000 to $42,000	19	380	3,790
$42,000 to $44,000	20	400	4,190
$44,000 to $46,000	21	420	4,610
$46,000 to $48,000	22	440	5,050
$48,000 to $50,000	23	460	5,510
$50,000 to $52,000	24	480	5,990
$52,000 to $54,000	25	500	6,490
$54,000 to $56,000	26	520	7,010
$56,000 to $58,000	27	540	7,550
$58,000 to $60,000	28	560	8,110
$60,000 to $62,000	29	580	8,690
$62,000 to $64,000	30	600	9,290
$64,000 to $66,000	31	620	9,910
$66,000 to $68,000	32	640	10,550
$68,000 to $70,000	33	660	11,210
$70,000 to $72,000	34	680	11,890
$72,000 to $74,000	35	700	12,590
$74,000 to $76,000	36	720	13,310
$76,000 to $78,000	37	740	14,050
$78,000 to $80,000	38	760	14,810
$80,000 to $82,000	39	780	15,590
$82,000 to $84,000	40	800	16,390
$84,000 to $86,000	41	820	17,210
$86,000 to $88,000	42	840	18,050
$88,000 to $90,000	43	860	18,910
$90,000 to $92,000	44	880	19,790
$92,000 to $94,000	45	900	20,690
$94,000 to $96,000	46	920	21,610
$96,000 to $98,000	47	940	22,550
$98,000 to $100,000	48	960	23,510
$100,000 to $150,000	52	26,000	49,510
$150,000 to $200,000	56	28,000	77,510
$200,000 to $300,000	60	60,000	137,510
$300,000 to $500,000	63	126,000	263,510
$500,000 to $1,000,000	64	320,000	583,510
$1,000,000 up	65	.....	.....

column. The tax for any amount of net income not shown in the table is computed by adding to the total surtax for the largest amount shown which is less than the income, the surtax upon the excess over that amount at the rate indicated in the table. For example, if the amount of net income is $63,128, the surtax is the sum of $8,690 (the surtax upon $62,000 as shown by the table) plus 30 per cent of $1,128, or $338.40, making a total surtax of $9,028.40.

LIMITS OF SURTAX AND WAR EXCESS PROFITS TAX IN CASE OF SALE.

Sections 211 (b) and 337 of the Revenue Act of 1918 provide that "in the case of a bona fide sale of mines, oil or gas wells, or any interest therein, where the principal value of the property has been demonstrated by prospecting or exploration and discovery work, done by the taxpayer, the portion of the tax imposed by this section attributable to such sale shall not exceed 20 per cent of the selling price of such property or interest."

Regulations 45, article 13—"Surtax on the sale of mineral deposits.—Where the taxpayer by prospecting and locating claims, or by exploring and discovering undeveloped claims, has demonstrated the principal value of mines, oil or gas wells, which prior to his efforts had a merely nominal value, the portion of the surtax attributable to a sale of such property or of the taxpayer's interest therein shall not exceed 20 per cent of the selling price. Exploration work alone without discovery is not sufficient to bring a case within this provision. Shares of stock in a corporation owning mines, oil or gas wells do not constitute an interest in such property. To determine the application of this provision to a particular case, the taxpayer should first compute the surtax in the ordinary way upon his net income, including his net income from any such sale. The proportion of the surtax indicated by the ratio which the taxpayer's net income from the sale of the property, computed as prescribed in article 715 of Regulations 45, bears to his total net income is the portion of the surtax attributable to such sale, and if it exceeds 20 per cent of the selling price of the property such portion of the surtax shall be reduced to that amount."

In the case of a corporation the war and excess profits tax applicable to such a sale is limited to 20 per cent of the selling price in accordance with section 337 of the law.

What the Taxpayer Must Prove.

The taxpayer in order to take advantage of this clause in the law must prove—

(*a*) A bona fide sale.

(*b*) That the principal value of the property has been demonstrated by prospecting or exploration and development work done by the taxpayer.

This benefit will accrue only to the holdings of the taxpayer making the discovery.

In order to meet the requirements of the case to the satisfaction of the Commissioner, the taxpayer will be required to submit the information called for in Schedules III, VI, and VIII on pages 59, 62, and 65 of the Manual.

Tax On Corporations.[1]

Section 230 of the Revenue Act of 1918 levies, in lieu of the taxes imposed by section 10 of the Revenue Act of 1916, as amended by the Revenue Act of 1917 and by section 4 of the Revenue Act of 1917, upon the net income of *every corporation* not specifically exempted a tax at the following rates:

(1) For the calendar year 1918, 12 per cent of the amount of the net income in excess of the credits provided in section 236; and

(2) For each calendar year thereafter 10 per cent of such excess amount. See Part II of the Regulations.

War-Profits and Excess-Profits Tax.

Section 301 (a) of the Revenue Act of 1918 levies, in lieu of the tax imposed by Title II of the Revenue Act of 1917, but *in addition to* the other taxes imposed by this act, upon the total net income of *every corporation* not specifically exempted, for the taxable year 1918 a tax equal to the sum of the following:

First bracket.—Thirty per cent of the amount of the net income in excess of the excess profits credits (as determined under sec. 312) and not in excess of 20 per cent of the invested capital.

[1] In all cases involving returns of corporations Part II of Regulations 45 should be consulted.

Second bracket.—Sixty-five per cent of the amount of the net income in excess of 20 per cent of the invested capital.

Third bracket.—The sum, if any, by which 80 per cent of the amount of the net income in excess of the war-profits credits (determined under sec. 311) exceeds the amount of the tax computed under the first and second brackets. See Part II of the Regulations.

GROSS INCOME AND NET INCOME.

Gross income includes all gains and profits and income from any source whatever, subject to the specific exemptions listed in section 213 (b) and section 231 of the Revenue Act of 1918, actually received for the year for which the return is rendered, whether received in cash or its equivalent.

Net income is the amount remaining after all allowable deductions (as listed in sec. 214 (a) and (b) or sec. 234 (a) and (b) have been made from gross income.

BASIS FOR DEDUCTIONS.

Certain deductions from gross income are based upon the "Capital Sum"; credits are based upon "Invested Capital." It is necessary that these terms be clearly understood by the taxpayer in order to avoid confusion in making returns.

In general, the deductions from gross income allowed corporations are the same as allowed individuals, except that corporations may deduct dividends received from other corporations subject to the tax and may not deduct charitable contributions, and that insurance companies are permitted special deductions.

INVESTED CAPITAL.

The invested capital is defined in section 326 of the Revenue Act of 1918 as (1) actual cash bona fide paid in for stock or shares; (2) cash value of property, other than cash, bona fide paid in for stock or shares (as limited by the statute); and (3) paid in or earned surplus and undivided profits, not including surplus and undivided profits earned during the year.

The surplus and undivided profits, if not correctly reflected in the taxpayer's accounts, may be adjusted in accordance with Reg-

ulations 45. Several of the articles which must ordinarily be considered are set out below.

Regulations 45, article 839. Surplus and undivided profits: Allowance for depletion and depreciation.—Depletion, like depreciation, must be recognized in all cases in which it occurs. Depletion attaches to each unit of mineral or other property removed, and the denial of a deduction in computing net income under the Act of August 5, 1909, or the limitation upon the amount of the deduction allowed under the Act of October 3, 1913, does not relieve the corporation of its obligation to make proper provision for depletion of its property in computing its surplus and undivided profits.

Adjustments in respect of depreciation or depletion in prior years will be made or permitted only upon the basis of affirmative evidence that as at the beginning of the taxable year the amount of depreciation or depletion written off in prior years was insufficient or excessive, as the case may be.

Where deductions for depreciation or depletion have either on the books of the corporation or in its returns of net income been included in the past in expense or other accounts, rather than specifically as depreciation or depletion, or where capital expenditures have been charged to expense in lieu of depreciation or depletion, a statement indicating the extent to which this practice has been carried should accompany the return.

Regulations 45, article 842. Surplus and undivided profits property paid in and subsequently written off.—Where tangible or intangible property has been paid in to a corporation for stock or shares or as paid-in surplus and has subsequently been in whole or in part written off the books, the amount so written off may, upon evidence satisfactory to the Commissioner, be restored to the capital or surplus account subject to the following limitations:

(1) The amount restored must be reduced by a proper deduction for any depreciation, obsolescence, or depletion; and

(2) The aggregate amount included in computing invested capital on account of such property shall not exceed the amount which might have been included if such property had not been written off.

Regulations 45, article 844. Surplus and undivided profits reserve for depreciation or depletion.—If any reserves for depreciation or for depletion are included in the surplus account it

should be analyzed so as to separate reserves and leave only real surplus. Reserves for depreciation or depletion can not be included in the computation of invested capital, except to the following extent:

(1) Excessive depletion or depreciation included therein and which if charged off could be restored under article 871 may be included in the computation of invested capital; and

(2) Where depreciation or depletion is computed on the value as of March 1, 1913, or as of any subsequent date, the proportion of depreciation or depletion representing the realization of appreciation of value at March 1, 1913, or such subsequent date may, if undistributed and used or employed in the business, be treated as surplus and included in the computation of invested capital.

For the purpose of computing invested capital, depreciation or depletion computed on the value as of March 1, 1913, or as of any subsequent date, shall, if such value exceeded cost, be deemed a pro rata realization of cost and appreciation and be apportioned accordingly. Except as above provided, value appreciation (even though evidenced by an appraisal) which has not been actually realized and reported as income for the purpose of the income tax can not be included in the computation of invested capital, and if already reflected in the surplus account it must be deducted therefrom.

The term *Capital Sum* is here applied to the total amount returnable to the taxpayer through depletion, depreciation, and obsolescence allowances. It is to be clearly distinguished from the term "Invested Capital," which is the basis for the determination of war-profits credits and excess-profits credits of corporations. "Invested capital" is the actual cash or its equivalent, paid in, plus undistributed surplus profits, and no appreciation in the value of any asset may be included except as provided in article 844 (2).

"CAPITAL SUM" AND "INVESTED CAPITAL."

The "capital sum" has no necessary relation to the "invested capital." It may represent the investment of funds belonging to the taxpayer, or the investment of borrowed funds, which have no relation to invested capital; under the provisions of the law and regulations, the capital sum may include amounts based upon the right of valuation as of March 1, 1913, or within 30 days after the

discovery of oil or gas by the taxpayer. (See Proof of Discovery, page 45.)

Where such valuations are allowable, they have no application to invested capital, except in accordance with article 844 (2) of Regulations 45, and may not be used for any purpose other than as a basis for depletion, depreciation, and obsolescence, or as a basis upon which to determine the gain or loss arising from the sale or surrender of property acquired prior to March 1, 1913. With respect to any allowance for amortization the basis is the cost of property acquired after April 5, 1917, and no amount may be added on account of revaluation.

The application of these principles is indicated in the following:

A corporation had a paid-up capital stock of $50,000. This amount was invested in oil and gas property and in addition the corporation had incurred liabilities due to developing the property and the purchasing of equipment at the beginning of the taxable year amounting to $50,000. The property was found to have a value of $150,000 in accordance with the valuation accepted by the Commissioner. The allowable deductions for depletion and depreciation in determining the net income of the corporation are computed on the value of $150,000. The actual invested capital for the purpose of calculating the tax due for the taxable year from the corporation is $50,000. However, in the succeeding taxable year a part of the aggregate allowance for depletion and depreciation (proportionate to the part of the capital sum representing appreciation) may be included in invested capital in accordance with the provision of article 844 (2) of Regulations No. 45. The following statement is prepared to illustrate the application of the law to the case cited:

Assuming the total deduction for depletion, depreciation, and obolescence from the gross income to be 10 per cent of the valuation accepted by the Commissioner, the amount deductible for the taxable year would be	$15,000
Amount of depletion, depreciation, and obsolescence calculated on the cost of the property is	10,000
The amount of realized appreciation which may be added to invested capital for the succeeding year is	5,000
Assuming that all the earnings are distributed, except the depletion and depreciation reserves, at the beginning of the succeeding taxable year, the invested capital would be	55,000
The cost of the property would be	90,000
The appreciation in value would be	45,000

Physical property is defined as all equipment having an inventory or salvage value and subject to removal from the property, such as buildings, bridges, and power plants; derricks, casings, drilling equipment (cable and rotary), and pumping equipment, including engines, boilers, tubing, and rods; flow lines, and connections on wells, tanks attached to wells, and other tankage of steel, wood, or concrete; cleaning and pulling equipment; salt-water equipment; refineries, treating and reducing plants, including casinghead gas plants; telegraph and telephone lines, pipe lines and tank cars, and all other equipment used in the production, reduction, conservation, or transportation of oil and gas or their products.

Cost of property includes all amounts (in cash or its equivalent) paid for and incident to the establishment of title and acquisition of the lease or freehold, as the case may be, such as—

Purchase price of lease or freehold.

Salaries or commissions paid to brokers or agents.

Fees to geologists, attorneys, surveyors, etc., for examination and defense of title, establishing boundaries, etc., State and county fees for recording and legalizing transfers, and all other payments made in acquiring and establishing title to the properties.

Cost of development comprises all payments made for and incident to the drilling of wells, such as cost of—

(1) Physical property.

(2) Geological and other surveys, made subsequent to acquisition.

(3) Roads.

(4) Water supplies.

(5) Hauling.

(6) Wages.

(7) Drilling.

(8) Shooting.

(9) Overhead charges (incident to drilling of wells).

(10) Fuel; and

(11) All other similar expenditures.

Both "Cost of Property" and "Cost of Development," in so far as they have not been decreased by allowable deductions, are chargeable to capital sum and are returnable through the several allowable deductions. Structures and equipment may also be included in capital assets and are returnable through depreciation.

In the case of revaluations as of March 1, 1913, or within 30 days of a discovery by the taxpayer made subsequent to February 28, 1913, the value thus established plus subsequent costs not otherwise deducted becomes the total of "Capital Sum." This revaluation, however, does not affect the Invested Capital, as explained on page 7.

Development costs (except the cost of physical property) may be deducted as an expense in the year in which they are paid out or at the option of the taxpayer may be charged to capital sum. Election once made under this option is final and will control the returns for all subsequent years.

EXPENSES.

Expense includes all amounts paid out (exclusive of amounts paid for physical property and development charged to Capital Sum) incident to the development and operation of producing properties and the preparation of their product for market, such as costs of pumping, cleaning, reshooting (including cost of torpedoes), gauging, storing, treating, reducing, repairs and maintenance, transporting, refining, conserving, marketing, overhead expense, insurance, etc.

The cost of repairs and replacements made necessary through deterioration of equipment may be charged off as expense, but if this is done the amount allowed as a depreciation deduction will be reduced.

In all cases items of expense must be charged off as such for the year incurred and can neither be deducted from the income of subsequent years as expense nor added to Capital Sum.

Repairs.—The cost of incidental repairs which neither materially add to the value of the property nor appreciably prolong its life, but keep it in an ordinary efficient operating condition, may be deducted as expense, provided the plant or property account is not increased by the amount of such expenditures. Repairs in the nature of replacements, to the extent that they arrest deterioration and appreciably prolong the life of the property, should be charged against the depreciation reserve.

Improvements and betterments.—Amounts expended for additions and betterments or for furniture and fixtures, which constitute an increase in capital assets or add to their value, are

not a proper deduction, but such expenditures when capitalized may be reduced through annual depreciation deductions.

COMPENSATION FOR PERSONAL SERVICES.

Among the ordinary and necessary expenses paid or incurred in carrying on any trade or business may be included a reasonable allowance for salaries or other compensation for personal services actually rendered. The test of deductibility in the case of compensation payments is whether they are reasonable and are in fact payments purely for services.

Bonuses to employees.—Gifts or bonuses to employees will constitute allowable deductions from gross income when such payments are made in good faith and as additional compensation for the services actually rendered by the employees, provided such payments, when added to the stipulated salaries, do not exceed a reasonable compensation for the services rendered.

Donations made to employees and others, which do not have in them the element of compensation or are in excess of reasonable compensation for services, are considered gratuities and are not deductible from gross income.

TIME FOR DEDUCTION OF CHARGES.

Each year's return, so far as practicable, both as to gross income and deductions therefrom, should be complete in itself, and taxpayers are expected to make every reasonable effort to ascertain the facts necessary to make a correct return.

The expenses, liabilities or deficit of one year can not be used to reduce the income of a subsequent year. A person making returns on an accrued basis has the right to deduct all authorized allowances, whether paid in cash or set up as a liability, and it follows that if he does not within any year pay or accrue certain of his expenses, interest, taxes, or other charges, and make no deduction therefor, he can not deduct from the income of the next or any subsequent year any amounts then paid in liquidation of the previous year's liabilities. A loss from theft or embezzlement occurring in one year and discovered in another is deductible only for the year of its occurrence.

Any amount paid pursuant to a judgment or otherwise on account of damages for personal injuries, patent infringements, or

otherwise, is deductible from gross income when the claim is liquidated or put in judgment or actually paid, less any amount of such damages as may have been compensated for by insurance or otherwise.

If subsequent thereto, however, a taxpayer has for the first time ascertained the amount of a loss sustained during a prior taxable year and not deducted from the gross income therefor, he may render an amended return for such preceding taxable year, including such amount of loss in the deductions from gross income, and may file a claim for refund for the excess tax paid by reason of the failure to deduct such loss in the original return. Provided that no such credit or refund shall be allowed or made after five years from the date when the return was due, unless before the expiration of such five years a claim therefor is filed by the taxpayer.

TAXES.

Federal taxes (except income, war-profits, and excess-profits taxes), State and local taxes (except taxes assessed against local benefits of a kind tending to increase the value of the property assessed), and taxes imposed by possessions of the United States or by foreign countries (except the amount of income, war-profits, and excess-profits taxes allowed as a credit against the tax), are deductible from gross income. See section 222 of the statute and articles 381 et seq. of Regulations 45 as to tax credits.

Postage is not a tax. Amounts paid to States under secured-debts laws in order to render securities tax exempt are deductible. Automobile license fees are ordinarily taxes.

LOSSES.

Losses sustained during the taxable year and not compensated for by insurance or otherwise are fully deductible (except by nonresident aliens) if—

(*a*) Incurred in the taxpayer's trade or business;

(*b*) Incurred in any transaction entered into for profit; or

(*c*) Arising from fires, storms, shipwreck, or other casualty, or from theft.

They must usually be evidenced by closed and completed transactions. In the case of the sale of assets the loss will be the difference between the cost thereof, less depreciation sustained since

acquisition, or the value as of March 1, 1913, if acquired before that date, less depreciation since sustained, and the price at which they were disposed of.

When the loss is claimed through the destruction of property by fire, flood, or other casualty, the amount deductible will be the difference between the cost of the property; or its value as of March 1, 1913, and the salvage value thereof, after deducting from the cost or value as of March 1, 1913, the amount, if any, which has been or should have been set aside and deducted in the current year and previous years from gross income on account of depreciation, and which has not been paid out in making good the depreciation sustained. But the loss should be reduced by the amount of any insurance or other compensation received.

Losses in illegal transactions are not deductible.

Losses of oil and gas are of two kinds: (*a*) Those which are unforeseen or unavoidable, such as losses sustained through fire or accident; and (*b*) losses that are anticipated and recognized as unavoidable under operating conditions, such as evaporation of oil in storage, ordinary leakage, refinery losses, etc.

Usually the latter class are indeterminate as to amount and are absorbed either implicitly or explicitly in current operating expenses or in cost of the oil or gas. Indeterminate losses may not be deducted from gross income.

DEPRECIATION.

Quotation from law.—Section 214 (*a*) (10):

> In the case of mines, oil and gas wells, other natural deposits, and timber a reasonable allowance for depletion . . . and for depreciation of improvements, according to the peculiar conditions of each case, based upon cost including cost of development not otherwise deducted.

Definition.—The term *depreciation* is used to cover the waste of assets due to exhaustion, wear and tear, and obsolescence of property, and is not to be confused with the depletion of the natural deposits of oil and gas due to the removal of these commodities in the course of exploitation of any property.

Depreciation Allowance.

Regulations 45, article 161.—A reasonable allowance for the exhaustion, wear and tear, and obsolescence of property used in

the trade or business may be deducted from gross income. The proper allowance for such depreciation of any property used in the trade or business is that amount which should be set aside for the taxable year in accordance with a consistent plan by which the aggregate of such amounts for the useful life of the property in the business will suffice, with the salvage value at the end of such useful life, to provide in place of the property its cost or its value as of March 1, 1913, if acquired by the taxpayer before that date.

Depreciable Property.

Regulations 45, article 162.—The necessity for a depreciation allowance arises from the fact that certain property used in the business gradually approaches a point where its usefulness is exhausted. The allowance should be confined to property of this nature. In the case of tangible property it applies to that which is subject to wear and tear, to decay or decline from natural causes, to exhaustion, and to obsolescence due to the normal progress of the art or to becoming inadequate to the growing needs of the business. It does not apply to inventories or to stock in trade, nor to land apart from the improvements or physical development added to it. It does not apply to bodies of minerals which through the process of removal suffer depletion, other provisions for this being made in the statute. Property kept in repair may, nevertheless, be the subject of a depreciation allowance. The deduction of an allowance for depreciation is limited to property used in the taxpayer's trade or business. No such allowance may be made in respect to automobiles or other vehicles used chiefly for pleasure, a building used by the taxpayer solely as his residence, nor in respect of furniture or furnishings therein, personal effects, or clothing; but properties and costumes used exclusively in a business, such as a theatrical business, may be the subject of a depreciation allowance.

Depreciation of Intangible Property.

Regulations 45, article 163.—Intangibles, the use of which in the trade or business is definitely limited in duration, may be the subject of a depreciation allowance. Examples are patents and copyrights and limited leases, licenses, and franchises.

Capital Sum Returnable through Depreciation Allowances.

Regulations 45, article 165.—The capital sum to be replaced by depreciation allowances is the cost of the property in respect of which the allowance is made, except that in the case of property acquired by the taxpayer prior to March 1, 1913, the capital sum to be replaced is the fair market value of the property as of that date. In the absence of proof to the contrary, it will be assumed that such value as of March 1, 1913, is the cost of property less depreciation up to that date. To this sum should be added from time to time the cost of improvements, additions, and betterments, the cost of which is not deducted as an expense in the taxpayer's return, and from it should be deducted from time to time the amount of any definite loss or damage sustained by the property through casualty, as distinguished from the gradual exhaustion of its utility which is the basis of the depreciation allowance. In the case of the acquisition after March 1, 1913, of a combination of depreciable and non-depreciable property for a lump price, as, for example, land and buildings, the capital sum to be replaced is limited to that part of the lump price which represents the value of the depreciable property at the time of such acquisition, such value to be ascertained, if necessary, by estimate.

Method of Computing Depreciation Allowances.

Regulations 45, article 166.—The capital sum to be replaced should be charged off over the useful life of the property either in equal annual installments or in accordance with any other recognized trade practice, such as an apportionment of the capital sum over units of production. Whatever plan or method of apportionment is adopted must be reasonable and should be described in the return.

Modification of Method of Computing Depreciation.

Regulations 45, article 167.—If it develops that the useful life of the property has been underestimated, the plan of computing depreciation should be modified and the balance of the cost of the property, or its fair market value as of March 1, 1913, not already provided for through a depreciation reserve, should be spread over the estimated remaining life of the property.

A taxpayer who in computing depreciation allowance in returns for years prior to 1918 has not taken ordinary obsolescence into consideration may for the year 1918, and subsequent years, revise the estimate of the useful life of any property so as to allow for such future obsolescence as may be expected from experience to result from the normal progress of the art. No modification of the method should be made on account of changes in the market value of the property from time to time, such as, on the one hand, loss in rental value of buildings due to deterioration of the neighborhood, or, on the other hand, appreciation due to increased demand. The conditions affecting such market values should be taken into consideration only so far as they affect the estimate of the useful life of the property.

Charging Off Depreciation.

Regulations 45, article 170.—A depreciation allowance, in order to constitute an allowable deduction from gross income, must be charged off. The particular manner in which it shall be charged off is not material, except that the amount measuring a reasonable allowance for depreciation must be deducted directly from the book value of the assets or, preferably, credited to a depreciation reserve account, which must be reflected in the annual balance sheet. The allowances should be computed and charged off with express reference to specific items, units, or groups of property, each item or unit being considered separately or specifically included in a group with others to which the same factors apply. The taxpayer should keep such records as to each item or unit of depreciable property as will permit the ready verification of the factors used in computing the allowance for each year for each item, unit, or group.

Closing Depreciation Account as to Any Item.

Regulations 45, article 171.—If the use of the property in the business is permanently discontinued, although no sale or other disposition of the property has been made, a determination of any gain or loss may be made; but any deduction in respect of any loss thereon must be disclosed in the taxpayer's return for the year in which the determination is made, and a full statement of the facts and the basis upon which the computation is calculated must be

attached to the return. Upon a sale or other disposition of the property, the consideration received shall be compared with the amount of the estimated salvage value used in computing the gain or loss as above provided, and the amount of the difference shall be treated as a gain or loss, as the case may be, of the year in which the sale or other disposition was made.

Depreciation of Improvements in the Case of Oil and Gas Wells.

Regulations 45, article 225.—Both owners and lessees operating oil and gas properties will, in addition to and apart from the deduction allowable for the depletion and return of capital as provided, be permitted to deduct a reasonable allowance for depreciation of physical property, such as machinery, tools, equipment, pipes, etc., so far as not in conflict with the option exercised by the taxpayer under article 223. The amount deductible on this account shall be such an amount based upon its capitalized value or cost equitably distributed over its useful life as will bring such property to its true salvage value when no longer useful for the purpose for which such property was acquired. Accordingly, where it can be shown to the satisfaction of the Commissioner that the reasonable expectation of the economic life of the oil or gas deposit with which the property is connected is shorter than the normal useful life of the physical property, the amount annually deductible for depreciation may for such property be based upon the length of life of the deposit. See article 161 et seq.

Depletion and Depreciation of Oil and Gas Wells in Years before 1916.

Regulations 45, article 226.—If upon examination it is found that in respect of the entire drilling cost of the wells, including physical property and incidental expenses, between March 1, 1913, and December 31, 1915, a taxpayer has been allowed a reasonable deduction sufficient to provide for the elements of exhaustion, wear and tear, and depletion, it will not be necessary to reopen the returns for years prior to 1916 in order to show separately in these years the portions of such deduction representing depletion and depreciation, respectively. Such separation will be required to be made of the reserves for depreciation at January 1, 1916, and

proper allocation between depreciation and depletion must be maintained after that date. In any case in which it is found that the deductions taken between March 1, 1913, and December 31, 1915, are not reasonable, amended returns may be required for these years.

See Part II.

In general, taxpayers claiming depreciation deductions will be required to submit the information called for in Schedule V, page 62.

AMORTIZATION.

The Revenue Act of 1918, section 214 (*a*) states that in computing net income there shall be allowed as a deduction:

(9) In the case of buildings, machinery, equipment and other facilities constructed, erected, installed, or acquired on or after April 6, 1917, for the production of articles contributing to the prosecution of the present war, and in the case of vessels constructed or acquired on or after such date for the transportation of articles or men contributing to the prosecution of the present war, there shall be allowed a reasonable deduction for the amortization of such part of the cost of such facilities or vessels as has been borne by the taxpayer, but not again including any amount otherwise allowed under this title or previous acts of Congress as a deduction in computing net income. At any time within three years after the termination of the present war the Commissioner may, and at the request of the taxpayer shall, reexamine the return, and if he then finds as a result of an appraisal or from other evidence that the deduction originally allowed was incorrect the taxes imposed by this title and by Title III for the year or years affected shall be redetermined, and the amount of tax due upon such redetermination, if any, shall be paid upon notice and demand by the collector, or the amount of tax overpaid, if any, shall be credited or refunded to the taxpayer, in accordance with the provisions of section 252.

To determine the deduction allowable under this provision see Regulations 45, Revised, arts. 181-188.

DEPLETION OF OIL AND GAS WELLS.

Depletion may be defined as the loss sustained through the progressive exhaustion of a mineral deposit.

Depletion allowances are made in recognition of the fact that oil and gas deposits are exhaustible and that each unit of oil and gas removed reduces the amount recoverable, and hence reduces the value of the property. Act of 1918, section 214 (*a*), states: That in computing net income there shall be allowed as deductions:

(10) In the case of mines, oil and gas wells, other natural deposits, and timber, a reasonable allowance for depletion and for depreciation of improvements, according to the peculiar conditions of each case, based upon cost, including cost of development not otherwise deducted: *Provided*, That in the case of such properties acquired prior to March 1, 1913, the fair market value of the property (or the taxpayer's interest therein) on that date shall be taken in lieu of cost up to that date: *Provided further*, That in the case of mines, oil and gas wells discovered by the taxpayer on or after March 1, 1913, and not acquired as the result of purchase of a proven tract or lease, where the fair market value of the property is materially disproportionate to the cost of the depletion allowance shall be based upon the fair market value of the property at the date of the discovery, or within 30 days thereafter; such reasonable allowance in all the above cases to be made under rules and regulations to be prescribed by the commissioner, with the approval of the Secretary. In the case of leases the deductions allowed by this paragraph shall be equitably apportioned between the lessor and lessee. . . .

A reasonable deduction for depletion of natural deposits and for depreciation of improvements is permitted, based—

(*a*) Upon cost, if acquired after February 28, 1913; or

(*b*) Upon the fair market value as of March 1, 1913, if acquired prior thereto; or

(*c*) Upon the fair market value within 30 days of discovery in the case of mines, oil and gas wells, discovered by the taxpayer after February 28, 1913, where the fair market value is disproportionate to the cost.

The essence of this provision is that the owner of such property, whether it be leasehold or freehold, shall secure through an aggregate of annual depletion and depreciation deductions the amount indicated in (*a*), (*b*), or (*c*), whicheve applies to his particular case, plus in any case the subsequent cost of plant and equipment (less salvage value) and underground and overground development, which is not chargeable to current operating expense, but not including land values for purposes other than the extraction of minerals. Operating owners, lessors, and lessees are entitled to deduct an allowance for depletion, but a stockholder in a mining or oil or gas corporation is not.

It should be noted that in this and following paragraphs the privilege of revaluation within 30 days of discovery applies to the discoverer solely. No revaluation after March 1, 1913, is allowed where the value of property is enhanced by discovery made by any other than the taxpayer.

Capital Recoverable through Depletion Allowance in Case of an Owner.

In the case of operating owner in fee or lessor the capital recoverable through depletion allowances consists in—

(*a*) Cost of the property, or its fair market value as of March 1, 1913, if acquired prior thereto, or its fair market value within 30 days of discovery, as the case may be; plus

(*b*) Cost of subsequent improvements and development not charged to current operating expenses; minus

(*c*) Deductions for depletion which have or should have been taken to date; and minus

(*d*) The portion of the capital sum as to which depreciation instead of depletion has been and is being deducted.

The cost or value stated under (*a*) does not include the value of the land other than as the container of oil and gas. Depletion may be claimed against that portion of the cost or value which resides in the mineral deposit which is being exploited. To obtain this it is necessary to deduct from total cost or value the cost or value of the property other than as a container of oil and gas.

Obviously, the *lessor* may not include in his capital sum any part of the discovery value or any part of the sums expended by the lessee in the development of the property, as mentioned under (*b*), and the operating owner in fee may include only such costs or values as have not been deducted as current operating expense or otherwise.

Where depletion deductions for former years have or should have been taken, these amounts are to be subtracted from the capital sum returnable through depletion deductions.

In no case shall the account returnable through deductions for depletion include items against which depreciation is being charged; that is, the cost (or value) of physical property may not be included, since it is returnable through depreciation deductions.

Capital Recoverable through Depletion Allowances in the Case of Lessee.

Regulations 45, article 203.—In the case of the lessee the capital remaining in any year recoverable through depletion allowances is the sum of

(*a*) The cost of the leasehold, or its fair market value as of

March 1, 1913, or its fair market value within 30 days after discovery; plus

(*b*) The cost of subsequent improvements and development not charged to current operating expenses, but minus

(*c*) Deductions for depletion which have or should have been taken to date, and

(*d*) The portion of the capital sum, if any, as to which depreciation instead of depletion should be charged.

Bonuses constitute a part of the cost of the leasehold. (See cost of property, p. 9.) Any annual or periodical rents or flat royalties (as in the case of gas wells) *supplementing the bonuses or other amount paid for the lease at the time of acquisition* may be charged to cost of leasehold until the property reaches the operating stage and will form part of the capital returnable through deductions for depletion.

Illustration

A's invested capital in a leasehold on March 1, 1913, was $200,000.

His estimated oil reserves on that date were 2,000,000 barrels.

Under the Act of 1913, the lessee was not allowed a revaluation for purposes of computing his depletion deduction from gross income. And the depletion taken could not exceed 5 per cent of the value of the oil at the well.

$\frac{200{,}000}{2{,}000{,}000}$, or 10 cents, represents the unit cost of each barrel of oil in the property at that date.

He extracts and sells—

200,000 barrels in 1913 for	$100,000
150,000 barrels in 1914 for	90,000
125,000 barrels in 1915 for	60,000
100,000 barrels in 1916 for	50,000
75,000 barrels in 1917 for	100,000
He has sold 650,000 barrels for	$400,000

	Depletion Sustained.	Depletion Allowed.
1913	$20,000	$5,000
1914	15,000	4,500
1915	12,500	3,000
1916	10,000	10,000
1917	7,500	7,500
Total	$65,000	$30,000

For purposes of taxation in 1918 A's invested capital is $200,000 − 65,000 = $135,000 and not $200,000 − 30,000 = $170,000.

The Revenue Act of 1918 allows A to revalue his property as of March 1, 1913. The valuation ("Capital Sum") claimed by A and allowed by the Commissioner was $1,000,000.

The unit cost for purposes of computing depletion deductions from capital assets is $\frac{\$1,000,000}{2,000,000}$, or $0.50 per barrel.

The total depletion of capital sum to January 1, 1918, was, therefore, 650,000 × $0.50 = $325,000.

Capital sum at January 1, 1918, is, therefore, $1,000,000 − $325,000, or $675,000, and not $1,000,000 − $30,000, or $970,000.

Apportionment of Deductions between Lessor and Lessee.

Regulations 45, article 204.—As the value of the property comprehends the interests of both lessor and lessee, no computation for the purpose of depletion allowances, of the value of these interests separately as of any date which combined exceeds the value of the property in fee simple will be permitted. The same principle apples to holders of fractional interests. If the aggregate deduction claimed is deemed excessive, the Commissioner may request the owner or lessee to show that the valuation claimed does not exceed the fair market value of the property at a specified date determined in the manner explained in Regulations 45, article 206. The lessor and lessee shall, with the approval of the Commissioner, equitably apportion the allowance in the light of the peculiar conditions in each case and on the basis of their respective interests therein. To the return of every taxpayer claiming an allowance for depletion in respect of (*a*) a property in which he owns a fractional interest only, or (*b*) a leasehold, or (*c*) a property subject to a lease, there shall be attached a statement setting forth the name and address and the precise nature of the holdings of each person interested in the property.

In the case of the *lessor*, the depletion deduction is computed like that of the operating owner, except that ordinarily the only amount of capital to be returned is the cost of the oil or gas deposit if acquired subsequent to March 1, 1913, or its fair market value *en bloc* as of March 1, 1913, if acquired prior thereto, or within 30 days of discovery of oil or gas wells *if discovered by the taxpayer.*

The value of the land for purposes other than as a container of oil or gas must always be deducted from the cost or value above to obtain the cost or value of the oil or gas deposits.

Such cost or value divided by the estimated units of oil or gas in the ground on the date of acquisition or valuation will give the unit cost or value to be applied against the number of units removed from the lessor's property by the lessee, irrespective of the amount of oil received by the lessor as royalty. However, in cases where the property was leased before March 1, 1913, at a *fixed price per unit*, instead of a royalty payable in kind the lessor would be restricted by the valuation indicated by such fixed price, as fluctuations in the market value of oil subsequent to the lease would affect the valuation of the lessee only.

DETERMINATION OF COSTS OF DEPOSITS.

Regulations 45, article 205.—In any case in which a depletion or depreciation deduction is computed on the basis of the cost or price at which any mine, mineral deposit, mineral rights, or leasehold was acquired, the owner or lessee will be required upon request of the Commissioner to show that the cost or price at which the property was bought was fixed for the purpose of a bona fide purchase and sale, by which the property passed to an owner, in fact as well as in form, different from the vendor.

No fictitious or inflated cost or price will be permitted to form the basis of any calculation of a depletion or depreciation deduction, and in determining whether or not the price or cost at which any purchase or sale was made represented the actual market value of the property sold, due weight will be given to the relationship or connection existing between the person selling the property and the buyer thereof.

In general, the taxpayer will be required to submit the information called for in Schedule I, page 47.

DETERMINATION OF FAIR MARKET VALUE.

Introductory Statement.

A determination of the fair market value of an oil or gas property (or the taxpayer's interest therein) is required:

(*a*) In connection with the computation of depletion allowances:

(1) *As of March* 1, 1913, in the case of properties acquired prior to that date; and

(2) *At the date of discovery or within* 30 *days thereafter* in the case of oil and gas wells, discovered by the taxpayer on or after March 1, 1913, and not acquired as the result of purchase of a proven tract or lease where the fair market value of the property is disproportionate to the cost.

(*b*) In connection with computing the amount which may be included in paid-in surplus, *as of date of conveyance*, where the tangible property has been conveyed to a corporation by gift or at a value accurately established or definitely known as at date of conveyance clearly and substantially in excess of the cash or of the par value of the stock or shares paid therefor.

(*c*) In connection with the computation of profit and loss from sale of capital assets in the case of properties acquired prior to *March* 1, 1913.

Regulations 45, article 206.—Where the fair market value of the property at a specified date in lieu of the cost thereof is the basis for depletion and depreciation deductions, such value must be determined, subject to approval or revision by the Commissioner, by the owner of the property in the light of the conditions and circumstances known at that date, regardless of later discoveries or developments in the property or in methods of mining or extraction.

The value sought should be that established assuming a transfer between a willing seller and a willing buyer as of that particular date.

No rule or method of determining the fair market value of mineral property is prescribed, but the Commissioner will lend due weight and consideration to any or all factors and evidence having a bearing on the market value, such as (*a*) cost, (*b*) actual sales and transfers of similar properties, (*c*) market value of stock or shares, (*d*) royalties and rentals, (*e*) value fixed by the owner for the purposes of the capital-stock tax, (*f*) valuation for local or State taxation, (*g*) partnership accountings, (*h*) records of litigation in which the value of the property was in question, (*i*) the amount at which the property may have been inventoried in probate court, (*j*) disinterested appraisal by approved methods, and (*k*) other factors.

In order to meet the requirements of the case to the satisfaction of the Commissioner the taxpayer will be required to submit the information called for in Schedule II. See also Proof of Discovery, page 45.

Ruling Regarding Valuation.

Valuation of fee under lease.—The valuation of a fee ownership in oil or gas land under lease acquired prior to March 1, 1913, will have to do with the equity in its oil and gas contents remaining to the owner of the fee title after deducting the value of the lessee's rights. But subsequent investments or discoveries by the lessee will not affect the lessor's valuation.

No Revaluation of Property Permitted.

Regulations 45, article 207.—The cost of the property or its fair market value at a specified date, as the case may be, plus subsequent charges to capital sum not deductible as current expenses, will be the basis for determining the depletion and depreciation deductions for each year during the continuance of the ownership under which the fair market value or cost was fixed, and during such ownership there can be no revaluation for the purpose of this deductoin. This rule will not forbid the redistribution of the capital sum over the estimated number of units remaining in the property in accordance with either of the next two articles.

Determination of Quantity of Oil in Ground.

Regulations 45, article 209.—In the case of either an owner or lessee it will be required that an estimate, subject to the approval of the Commissioner, shall be made of the probable recoverable oil contained in the territory with respect to which the investment is made as of the time of purchase, or as of March 1, 1913, if acquired prior to that date, or within 30 days after the date of discovery, as the case may be. The oil reserves must be estimated for all undeveloped proven land as well as producing land. If information subsequently obtained clearly shows the estimate to have been materially erroneous, it may be revised with the approval of the Commissioner.

The estimate of probable recoverable oil in the ground is fundamentally necessary if a reasonable deduction for depletion is to be calculated, and, while it may be impossible to determine exactly the future production of a well or tract, it has been found possible to predict future productions with a comparatively narrow limit of error. The result of analysis of a great volume of production records has led to the development of the methods suggested in Part III of the Manual.

Methods of Estimating Recoverable Reserves.

The Treasury Department does not prescribe any particular method of estimating recoverable reserves, but the methods described in Part IV of the Manual are applicable to a wide variety of conditions and are inserted as a suggestion.

The underlying principle of the methods outlined is that *the best indication of the future production of any well is to be found in the history of similar wells in the same or similar districts*, and that, other things being equal, a well's production is more likely to approximate the production of a similar well in the tract or district than to deviate widely from the average.

The method may be summarized as follows:

1. Plotting the record of production of individual wells, or, lacking such detailed information, the average production per well for each tract.

2. Deriving from these graphical records an average or composite production decline curve for the district.

3. Estimating from the last year's average production per well the probable future production, based on the average production decline curve, or a future production curve derived from the production decline curve

4. Ascertaining probable total future production of producing wells by multiplying average future production per well by the number of wells producing at the end of the year.

5. Estimating the probable future production of undeveloped proven land on the basis of near-by production, making due allowance for the decline in pressure due to the extraction of oil from the pool.

It is to be emphasized that the value of estimates will depend almost entirely upon the skill with which the method is carried

out and the character of the production records upon which they are based. Where accurate detailed records are not kept, it may be difficult to determine a "reasonable allowance for depletion."

The taxpayer may estimate his recoverable reserves by any method that can be shown to be well founded, but in all cases the data upon which such estimate was based must be submitted with a description of the method employed, and a résumé of the calculations.

COMPUTATION OF ALLOWANCE FOR DEPLETION OF OIL WELLS.

Regulations 45, article 210.—When the cost or value as of March 1, 1913, or within 30 days after the date of discovery of the property, shall have been determined, and the number of mineral units in the property as of the date of acquisition or valuation shall have been estimated, the division of the former amount by the latter figure will give the unit value for the purposes of depletion, and the depletion allowance for the taxable year may be computed by multiplying such unit value by the number of units of mineral extracted during the year. If, however, proper additions are made to the capital account represented by the original cost or value of the property, or circumstances make advisable a revised estimate of the number of mineral units in the ground, a new unit value for purposes of depletion may be found by dividing the capital account at the end of the year, less deductions for depletion to the beginning of the taxable year which have or should have been taken, by the number of units in the ground at the beginning of the taxable year. This number, unless a revision of the original estimate has been made, will equal the number of units in the ground at the date of original acquisition or valuation less the number extracted prior to the taxable year. If, however, a recalculation is made, the number of units at the beginning of the year will be the sum of the gross production of the year and the estimated mineral reserves in the property at the end of the year.

Each barrel of oil or unit of gas extracted and marketed must, before a profit can be realized, pay not only its proportionate share of the operating expense and deductions for depreciation and obsolescence of physical property, but also must pay its proportionate share of capital sum returnable through depletion allowances. (See above.)

This proportionate share of capital sum returnable through

depletion allowances, which each unit of oil or gas must pay, is *unit cost.*

Unit cost is obtained by dividing the capital sum returnable through depletion by the "*estimated recoverable* reserve" at the beginning of the taxable year.

The depletion deduction is computed by multiplying the unit cost by the number of units produced during he taxable year.

It is to be noted that the estimated recoverable reserves and the number of units produced are used in estimating the depletion deduction for both lessor and lessee. Since, however, they are applied to different capital amounts returnable through depletion deductions, the unit costs for lessee and lessor are not identical, and the deductions bear the same ratio as the capital sum of lessor and lessee. Usually the lessee's investment is greater than the lessor's and his deductions are correspondingly greater.

Stated in another way, if a certain proportionate part of the lessee's capital returnable through depletion deductions is deducted in a given year the same *proportion* of the lessor's capital sum returnable through depletion will be deducted.

(See apportionment of deductions between lessor and lessee.)

Illustration:

A, a lessee, has an oil lease in which his original investment (exclusive of value of physical property) was	$20,000
Development cost (exclusive of cost of physical property) not otherwise deducted	80,000
Capital returnable through depletion allowance	$100,000
Estimated recoverable reserves at end of taxable year.....barrels	400,000
Produced during taxable year..... "	100,000
Estimated oil at beginning of year..... "	500,000
Therefore unit cost is $\frac{\$100,000}{500,000}$, or per barrel	$0 20
A's depletion allowance for the taxable year is, therefore $0.20×100,000, or	$20,000
B, the owner in fee of the property, had invested	$40,000
Of which the value of the land exclusive of oil rights represents	25,000
The investment in the oil deposit is	$15,000
B's unit cost, is therefore, $\frac{\$15,000}{500,000}$, or per barrel	$0 03
And his depletion allowance for the same year $0.03×100,000, or	$3,000

The above example presupposes that B leased his land without bonus.

Any amount received by a lessor as bonus for an oil and gas lease on the property would reduce his capital sum by that amount.

Illustration:

The lessor's (B's) investment in the deposit is	$15,000
He receives as bonus	5,000
His net investment in the deposit is therefore	$10,000
He sells a one-half interest in his royalty for	$6,000
As this half cost him	5,000
His profit is	$1,000
And is subject to tax as income.	
His capital sum remaining is	$5,000
If he had sold a one-half interest in his royalty for	$4,000
He would have sustained a loss of	$1,000

and should deduct this amount from gross income as a loss in computing his tax.

COMPUTATIONS OF ALLOWANCE FOR DEPLETION OF GAS WELLS.

Regulations 45, article 211.—The deductions allowed in computing income from natural-gas properties are in general similar to those allowed oil operators, but the method of computing the deductions and the various assets differ in certain particulars, the most notable of which are involved in the problems of estimating the probable reserves and computing the depletion.

On account of the peculiar conditions surrounding the production of natural gas it is necessa y to compute the depletion allowance for gas properties by methods suitable to the particular cases. Usually the depletion should be computed on the basis of decline in closed or rock pressure, taking into account the effects of water encroachment and any other modifying factors. In many fields more or less additional evidence on depletion is to be had from such considerations as (*a*) details of production and performance records of well or property, (*b*) decline in open flow capacity, (*c*) comparison with the life histories of similar wells or properties, particularly those now exhausted, and (*d*) size of reservoir and pressure of gas.

METHODS OF COMPUTING GAS DEPLETION.

Details of production or the performance record of the well or property.—As a general rule the demand on a natural gas property is a variable factor. In certain fields, however, the demand from some wells has from the beginning, or for considerable periods, been greater than the supply, so that the amount of gas marketed per well may, as in the case of oil, show a regular decline, which will be indicative of the total amount that the well may be expected to produce and also the rate of production. Even where the demand does not greatly exceed the supply, the amount and rate of past production may in certain cases throw light on the future of the well or property.

Decline in open-flow capacity.—Where data are available the decline in open-flow capacity indicates in a general way the rate of exhaustion of the gas field. The relationship is not at all close and varies from field to field and from well to well. Also for most gas wells accurate data on decline in open-flow capacity are not available. Nevertheless it is probable that for certain properties this method will have value, for with rare exceptions the production of gas from a well leads to a decline in its capacity, and the fraction produced is roughly proportional to the decline.

Comparison with life history of similar wells or properties, particularly those now exhausted or nearing exhaustion.—Where no other data are available the rate of depletion of a gas well or property may be approximated by comparison with a neighboring well or property that has reached a later stage in life. Particularly is this applicable in a district where many gas wells have become exhasuted. For example, in a region where wells produce from 8 to 12 years, or an average of 10 years, a 10 per cent deduction will be a rough approximation of the rate of depletion.

Size of reservoir and pressure of gas, or the pore-space method.—For some properties the pore-space method may be best for estimating underground supplies of natural gas and for a good many it will furnish additional evidence of value. The method would be ideal if the average percentage of pore space, the extent and thickness of the sand, and the pressure of the gas could be accurately ascertained. In computing the reserves of an individual property by this method the migratory character of gas must be considered and the production and behavior of adjacent properties

taken into account. The factors that make the method difficult to apply are difficulty of accurately ascertaining the thickness of pay, limits of pool, percentage of pore space, the effect of encroaching water and oil, and the quantity of gas remaining when commercial production is no longer possible.

Take, for example, a pool where there is no encroachment by water. Suppose that the pore space is 25 per cent, the thickness of the pay 20 feet, and the extent of the pool 10 square miles, or roughly 280,000,000 square feet. The volume of the reservoir would be 1,400,000,000 cubic feet, and the amount of gas in the sand could be readily computed by taking into account the closed pressure of the wells.

Other indications of depletion.—Additional evidence of decreasing supply of natural gas in the ground is commonly observable in the behavior of the wells and the provision that must be made for transporting the gas to market. Observations on minute pressures show more or less progressive change as the wells become older and an increasing amount of gas is drawn from the ground. Line pressures and pressures at compressing stations are also likely to show a progressive change in the same direction. The appearance of water or oil in a gas well or in neighboring gas wells may be a very significant symptom of the approaching termination of the life of the well. The clogging of gas wells by paraffin, salt, or other deposits may demand modification of depletion estimates.

CLOSED-PRESSURE METHOD.

Because of its general applicability, the closed-pressure method is by far the best method of estimating the depletion of gas properties.

Unfortunately, accurate closed-pressure data have not been kept for all properties or perhaps even for the majority of properties, but the rock pressure in most pools is known or is ascertainable with a fair degree of accuracy, and the information drawn from the pressure decline is, with the exception of a few fields, not subject to profound modification, because of factors whose value can not be appraised. The basis of this method is Boyle's law. According to this law of physics, if gas is pumped into a vessel until the pressure is 200 pounds and then is drawn off until the pressure is 100 pounds, the size of the vessel remaining fixed, and ignoring for the moment

atmospheric pressure, it may be concluded that one-half of the gas has been drawn out of the vessel. If an underground gas reservoir of fixed dimensions is tapped by wells and the pressure is found to be a thousand pounds, and then if the gas is drawn off through the wells until the gas pressure in the pool is lowered to 100 pounds, we may infer that about nine-tenths of the supply of gas has been exhausted.

"Unit cost" as applied to natural gas.—Although, as a rule, the number of cubic feet of gas under a tract can not be satisfactorily estimated and the quantity that will be marketed is even less definite, the "unit cost method" can be used by regarding pounds of closed pressure as units, for the actual quantity of gas underground commonly varies with the decline in pressure and the relative quantity at the beginning and end of the tax year and at the time of abandonment, is, in the lack of better information, usable for tax purposes.

Corrections and refinements of closed-pressure method.—Several corrections and more or less important refinements are made in applying this method to the computation of depletion, and it should be borne in mind that it does not afford data on the *amount* of gas originally in the pool or at any later specified time, but only the *fraction* of the gas that has been removed from its natural reservoir and the fraction remaining in that reservoir. Perhaps the most important of these corrections arises out of the fact that the size of the reservoir does not remain fixed but becomes smaller as the gas is drawn and water or oil advances into a part of the space formerly occupied by the gas. The pressure is thus prevented from declining at a rate proportionate to the amount of gas drawn from the pool. The correction on account of water or oil encroachment is difficult to make, because of the lack of data to determine the extent of the encroachment. However, in a good many pools, after a study of the distribution of wells that have been "drowned out" and the history of water troubles in similar near-by pools, it is possible to make allowance for water or oil encroachment which will more or less closely approximate the facts.

Another refinement applicable to the computation of depletion of natural gas by the closed-pressure method is based upon the fact that even where there is no encroachment of water or oil the depletion is not precisely represented by the gauge readings,

though the errors are generally so small that they may be ignored. For example, where the pressure declines from 1,000 to 500 pounds, the gas is not exactly half gone, for the reason the pressures referred to are guage readings and to each should be added the pressure of the atmosphere—for most fields about 14.4 points to the square inch. The fraction remaining in the ground then becomes $\frac{514.4}{1014.4}$.

Account should also be taken of the pressure at which wells are abandoned in the field or district.

If wells can not be operated with profit after the pressure has declined to 25 pounds gauge reading (39.4 pounds absolute), then the percentage of recoverable gas remaining when the pressure has declined from 1,000 to 500 pounds gauge reading is not one-half or even the fraction $\frac{514.4}{1014.4}$ but $\frac{475}{975}$. The difference in the fraction where pressures of several hundred pounds are involved is not great and scarcely worth considering in view of the other errors which are certain to affect the result. However, after the pressure has declined to a low figure, the matter of correcting the fraction becomes of considerable importance. Thus, if the pressure of abandonment is 4 pounds guage reading and during the year the average closed pressure of a pool has declined from 10 pounds to 5 pounds gauge reading, five-sixths instead of one-half of the recoverable gas has been withdrawn.

Still another refinement that has, as a rule, more theoretical than practical value may be worthy of consideration in certain instances. This arises out of the fact the gases do not expand precisely as the pressure decreases, and that even if the size of the natural reservoir remains fixed the pressure does not decline in exact proportion to the amount of gas removed. The difference amounts to only a few per cent and is greatest for high pressures. In the decline from 1,000 to 500 pounds per square inch the gas expands several per cent more than would be calculated by a strict application of Boyle's law, and in a decline from 1,500 pounds to 1,000 pounds the departure is still greater. The correction varies from field to field because of the different constitution of the gases, though since most natural gases consist largely of methane the variations on account of differences in gases are not great.

A fourth detail of refinement arises out of the fact that on the average more gas is marketed for 50 pounds of decline in pressure after the pressure has reached 100 pounds or less than an equal decline while the pressure is high, as, for example, 1,000 pounds

per square inch. Also the expense of marketing gas after the pressure has become low is greater than when it was high, largely because of the necessity of installing compressors to push the gas through the pipe lines to the consumers. These two considerations have a tendency to balance each other and, with certain exceptions, will not be of sufficient importance to warrant an attempt to apply the corrections.

METHOD OF GAUGING.

In using the closed-pressure method of estimating depletion, the method of gauging is of vital importance and in many fields is not carried out with sufficient care. Care should be taken to make sure that the gauge is accurate, testing it before and after attaching it to the well. If it must be transported far or is subject to much jolting in transportation, a gauge tester should be taken along and used at the well.

Care should also be taken to empty the well of oil and water by pumping, blowing, or siphoning before attaching the gauge, for any liquid in the hole will lower the closed pressure reading.

The well should be closed long enough to allow the pressure to build up to its maximum. The length of time necessary for this purpose varies a great deal from field to field and well to well. The well should remain closed until the pressure will not build up more than 1 per cent in 10 minutes. Ordinarily, 24 hours will be sufficient for this purpose, but for some wells several days or even a longer period will be required, owing to the slowness of equalization of pressure in the sand.

APPORTIONMENT OF DEPLETION AMONG VARIOUS SANDS.

Where more than one sand under a property is yielding gas, the problem arises as to how to weight or evaluate the decline in pressure in the different sands. Suppose there is a very good gas sand in which the pressure declines from 600 to 300 pounds during the year, and a very poor sand in which the pressure declines from 800 to 750. The depletion sustained is not indicated by the average decline in pressure but is more nearly proportionate to the decline in the good sand. If accurate figures on capacities of wells are obtainable, it will be possible to make a fairly accurate weighting of the pressure declines, or if facts indirectly indicating ca-

pacity of individual wells are obtainable some light may be thrown on the question. But, as a general rule, it is necessary to average the decline of wells drawing from different sands as though they were drawing from the same sand.

SEASON FOR TESTING WELLS FOR CLOSED PRESSURE.

For many fields summer or early fall readings furnish the best indication of decline in closed pressure. It is therefore recommended that such readings be taken regularly and consistently. Summer or fall readings are of especial value because these seasons for most fields are at the end of a period during which the wells have not been subject to heavy draft, and hence are in best condition to accurately reflect the pressure of the gas in the underground pool or reservoir. If pressures of all wells or representative wells are observed regularly and carefully in summer or early fall, these readings may in many cases be applied direct to the end of the taxable year, though in some cases it may be possible and desirable to estimate the pressures at the end of the taxable year from pressures observed at other times. Obviously, it will not be possible to test the pressures of all wells at the exact end of the taxable year.

Simple examples.—If in one part of a tract a gas well is brought in at a pressure of 1,000 pounds and during the remainder of the taxable year the pressure declines to 700 pounds, the rough inference may be drawn that three-tenths of the gas has been taken from the tract and, subject to corrections in certain cases, three-tenths of the capital returnable through depletion may be charged off.

Suppose that sometime in the next taxable year a gas well is completed on another part of the tract and that its initial pressure is 800 pounds. If by the end of the year the pressure of this well has declined to 700 pounds while the pressure of the first well has dropped to 500 pounds, the fraction of the capital account returnable through depletion the second year, is proportional to the average decline in pressure, assuming that there are no water troubles or other noteworthy complications. The average of 700 and 800 is 750 and the average of 500 and 700 is 600. The difference or average decline in pounds or units of gas is 150, and this represents a decline of 20 per cent from 750. It will be noted that the exact date of completion of the new well does not enter the

computation and it is treated as though it were finished at the beginning of the year. The rate of decline within the year is of little consequence, the main consideration being the amount of decline for the whole year. If the year's decline occurred within a month, or even a week, it is treated the same as though it were spread over the entire year.

Abandoned wells may be regarded as fully depleted and their pressure counted as zero in computing depletion. Consider the wells just described and assume that in the third year a third well is brought in and one of the old wells is abandoned. Suppose the pressure at the first well declined from 500 pounds to about zero and the well is abandoned, the second well to 300 pounds and the third to 600. The pressure of the two old wells at the beginning of the year and of the new one at its completion averaged 600 pounds, and the average of the three at the end of the year was 300. The depletion indicated is 50 per cent of the remaining capital account.

It is suggested that the capital sum at the beginning of each year be treated as 100 per cent for the average pressure at the beginning of the year, and the average decline during the year will then furnish a readily usuable basis for computing the depletion allowance.

The amount of gas in the ground is, as a rule, to be regarded as limited to the proven territory so that as new wells are drilled and the territory is enlarged, or new gas-bearing sands are discovered, the denominator of the fraction, indicating depletion, varies from year to year.

FORMULA.

The following discussion is offered for the use of those who prefer to use a formula in computing the depletion allowance. Perhaps the simplest formula may be written:

$$\frac{x}{y} \times z = \text{depletion allowance.}$$

In this formula x stands for the capital sum to the end of the year; y is the total future pressure decline or the difference between the sum of the pressures at the beginning of the tax year and the sum of the pressures at the time of expected abandonment; z is

the pressure decline during the year as obtained by adding to the sum of the pressures at the beginning of the year the sum of the pressures of any new wells completed during the year and subtracting the sum of the pressures at the end of the year. The formula may also be written as follows:

$$\frac{\text{Capital sum to end of tax year}}{\text{Sum of the pressures at beginning of year} - \text{sum of pressures at time of expected abandonment.}} \times \begin{array}{l}\text{Sum of pressures at beginning of tax year} + \\ \text{sum of pressures of new wells} - \text{sum of pressures at end of tax year.}\end{array} = \text{Depletion allowance.}$$

GAS WELL PRESSURE RECORDS TO BE KEPT.

Regulations 45, article 212.—Beginning with 1919, closed-pressure readings of representative wells, if not of all wells, must be carefully made and kept. In order to standardize pressure readings, the well should remain closed until the pressure does not build up more than 1 per cent of the total pressure in 10 minutes. Ordinarily 24 hours will suffice for this purpose but some wells will need to remain closed for a longer period. Where the pressure builds up very slowly the 1 per cent in 10 minutes will be found too liberal. If there is any water in the well it should be blown, siphoned, or pumped off before the well is closed.

A closed-pressure reading of a gas well which has been producing, or is near gas wells that have been producing, is lower than the actual average pressure of the gas in the reservoir by an amount depending on the well's location with reference to other producing wells and the length of time it has been closed in.

It is necessary to record the length of time the well has been closed and to show how the pressure built up during this period. Successive readings will indicate the point at which the pressure becomes approximately stationary; that is, the point at which the closed pressure approaches as nearly as possible the maximum pressure which would be shown if all wells in the pool were closed for several months. The length of time required varies with the character of the sand, position of the packer, the location of the

well with reference to other wells, the limits of the pool, and other factors. The depth of the well, diameter of tubing, and line pressure when the well was shut off should be noted.

Since readings at the exact end of the taxable year will ordinarily not be available, the pressure of that date may be obtained by interpolation or extrapolation. In certain cases readings taken regularly in September or some other month may be applicable to the end of the taxable year. As a general rule September closed-pressure readings furnish the best indication of depletion, and it is recommended that such readings be made with regularity and care. Where interpolated or extrapolated readings are used, the data from which they are obtained should be given. Gauges should be of appropriate capacity and should be frequently tested. Record should be kept of the number of gauges, date each was tested, names of men testing, and other significant details.

COMPUTATION OF COMPLETION ALLOWANCES WHERE QUANTITY OF OIL OR GAS IS UNCERTAIN.

Regulations 45, article 213.—Computation of depletion allowance where quantity of oil or gas uncertain.—If by reason of the youth of the field, restricted production or for any other cause, it is not possible to determine with any degree of certainty the quantity of oil or gas in a property, it will be necessary to make a tentative estimate which will apply until production figures are available from which an accurate estimate may be made.

COMPUTATION OF DEPLETION ALLOWANCE FOR COMBINED HOLDINGS OF OIL PROPERTIES.

Regulations 45, article 214 (1).—The recoverable oil belonging to the taxpayer shall be estimated separately on the smallest unit on which data are available, such as individual wells or tracts, and these, added together into a grand total, to be applied to the total capital assets returnable through depletion.

The capital sum shall include the cost or value, as the case may be, of all oil rights, freeholds, or leases, plus all incidental costs of development not charged as expense.

The unit value of the total recoverable oil is the quotient obtained by dividing the total capital sum recoverable through

depletion by the total estimated recoverable oil at the beginning of the taxable year.

This unit multiplied by the total number of units of oil produced by the taxpayer during the taxable year from all of the oil properties will determine the amount which may be allowably deducted from the gross income of that year.

In the case of sale of particular tracts, full account must be taken of the depletion of such tracts in computing profit or loss thereon.

COMPUTATION OF DEPLETION ALLOWANCE FOR COMBINED HOLDINGS OF GAS PROPERTIES.

Regulation 45, article 214 (2).—In the case of gas properties of a taxpayer the depletion allowance for each pool may be computed by using the combined capital sum returnable through depletion of all tracts of gas land owned by the taxpayer in the pool and the average decline in rock pressure of all the taxpayer's wells in each pool in the formula given in article 211. The total allowance for depletion of the gas properties of the taxpayer will be the sum of the amounts computed for each pool.

The depletion of gas supplies belonging to a taxpayer may be more accurately computed by making estimates for each tract, though it is quite possible that the expense of making separate estimates for individual tracts may be greater than the benefits arising from such a procedure.

DEPLETION AND DEPRECIATION ACCOUNTS OF BOOKS.

Regulation 45, article 216.—Every taxpayer claiming and making a deduction for depletion and depreciation of mineral property shall keep accurate ledger accounts in which shall be charged the fair market value as of March 1, 1913, or within 30 days after the date of discovery, or the cost, as the case may be (*a*) of the property, and (*b*) of the plant and equipment, together with (*c*) such amounts expended for development of the property or additions to plant and equipment since that date as have not been deducted as expense in his returns.

These accounts shall be credited with the amount of the depreciation and depletion deductions claimed and allowed each year, or the amounts of the depreciation and depletion shall be credited

to depletion and depreciation reserve accounts, to the end that when the sum of the credits for depletion and depreciation equals the value or cost of the property plus the amount added thereto for development or additional plant and equipment, less salvage value of the physical property, no further deduction for depletion and depreciation with respect to the property will be allowed.

Because of the fact that depreciation and depletion deductions are applied against different capital sums, which are usually returnable at different rates, it is essential that these accounts be kept separately; that is, the cost or value of physical property subject to depreciation with deductions for depreciation enter into one account, while the cost or value of the property (exclusive of physical property), together with additions for such development costs as have not been charged to current operating expenses or deducted as depletion, enter into a separate account.

If dividends are paid out of a depletion or depreciation reserve, the stockholders must be expressly notified that the dividend is a return of capital and not an ordinary dividend out of profits.

DISTRIBUTION FROM DEPLETION OR DEPRECIATION RESERVE.

A reserve set up out of gross income by a corporation and maintained for the purpose of making good any loss of capital assets on account of depletion or depreciation is not a part of its surplus out of which ordinary dividends may be paid.

A distribution made from such a reserve will be considered a liquidating dividend and will constitute taxable income to a stockholder only to the extent that the amount so received is in excess of the cost or fair market value as of March 1, 1913, of his shares of stock. No distribution, however, will be deemed to have been made from such a reserve, except to the extent that the amount paid exceeds the surplus and undivided profits of the corporation.

In general, any distribution made by a corporation other than out of earnings or profits accumulated since February 28, 1913, is to be regarded as a return to the stockholder of part of the capital represented in his shares of stock, and upon a subsequent sale of such stock his profit will be the excess of the selling price over the cost of the stock or its fair market value as of March 1, 1913, after applying on such cost or value the amount of any such capital distribution.

STATEMENT TO BE ATTACHED TO RETURN WHERE DEPLETION OF OIL OR GAS IS CLAIMED.

Regtlations 45, article 218.—To each return made by a person owning or operating oil or gas properties there should be attached a statement showing for each property information called for in Schedules I, II, and IV.

(*a*) (1) The fair market value of the property (exclusive of machinery, equipment, etc., and the value of the surface rights) as of March 1, 1913, if acquired prior to that date; or (2) the fair market value of the property within 30 days after the date of discovery; or (3) the actual cost of the property, if acquired subsequent to February 28, 1913, and not covered by the foregoing clause:

(*b*) How the fair market value was ascertained, if the property came under (*a*) (1) or (*a*) (2) above (see sections relating to fair market value, p. 23);

(*c*) The estimated quantity of oil or gas in the property at the time that the value or cost was determined;

(*d*) The name and address of the person making the estimate and the manner in which this estimate was made, including a summary of the calculations;

(*e*) The amount of capital applicable to each unit (this being found by dividing the value or cost, as the case may be, by the estimated number of units of oil or gas, pounds per square inch in the case of gas) in the property at the beginning of the taxable year;

(*f*) The quantity of oil or gas produced during the year for which the return is made (in the case of new properties it is desirable that this information be furnished by months);

(*g*) The number of acres of producing and proven oil or gas land:

(*h*) The number of wells producing at the beginning and end of the taxable year;

(*i*) The date of completion of wells finished during the taxable year;

(*j*) The date of abandonment of all wells abandoned during the taxable year;

(*k*) A legal description of the property, with a property map

showing the location of the property and of the producing and abandoned wells, dry holes, and proven oil and gas land;

(*l*) The average gravity of the oil produced on the tract;

(*m*) The number of pay sands and average thickness of each pay sand or zone on the property;

(*n*) The average depth to the top of each of the different pay sands;

(*o*) Any data regarding change in operating conditions, such as flooding, use of compressed air, vacuum, shooting, etc., which have a direct effect on the production of the property;

(*p*) The monthly or annual production of individual wells and the initial daily production of new wells (this is highly desirable information and should be furnished wherever possible);

(*q*) (For the first year in which the above information is filed for a property which was producing prior to the taxable year covered by the above statement the following information must be furnished.) Annual production of the tract or of the individual wells, if the latter information is available, from the beginning of its productivity to the beginning of the taxable year for which the return was filed; the average number of wells producing each year; and the initial daily production of each well; and

(*r*) Any other data which will be helpful in determining the reasonableness of the depletion deduction.

Maps.

Maps that accompany records and delineate property boundaries must be sufficiently extended to show the position of property in relation to section, township, and range lines, or in areas of metes and bounds survey, the relation to two or more established lines, of either township or district.

On some part of the map should be recorded the name of the State, county, township, or district, name of the company or individual representing property, scale of map, and date of survey, and points of the compass.

It will be to the advantage of every taxpayer to assist the department in compiling complete statistics of all development that has taken place, and maps submitted should show location of all wells that have ever been drilled on a given property. The character of each well should be indicated by appropriate symbols.

Where wells have been drilled by another company or individual it is advisable to distinguish such wells by some symbol or abbreviation, explaining the symbol in a marginal note.

When a taxpayer has filed adequate maps with the Commissioner he may be relieved of filing further maps of the same properties, provided all additional information necessary for keeping the maps up to date is filed each year. This includes records of dry holes as well as producing wells, together with logs, depth, and thickness of sands, location of new wells, etc.

By "production" is meant the net production of oil or gas belonging to the taxpayer.

In those leases where no account is kept of the oil or gas used for fuel, the net production will necessarily be that remaining after the fuel used in the property has been taken out. In cases of this kind an estimate of the fuel used from each tract should be given for each year.

REVALUATION OF OIL OR GAS PROPERTIES DISCOVERED SINCE MARCH 1, 1913.

Section 214 (*a*) and 234 (*a*) of the Revenue Act of 1918, state—

that in the case of mines, oil and gas wells, discovered by the taxpayer on or after March 1, 1913, and not acquired as a result of purchase of a proven tract or lease, where the fair market value of the property is materially disproportionate to the cost, the depletion allowance shall be based on the fair market value of the property at the date of the discovery or within 30 days thereafter; such reasonable allowance . . . to be made under rules and regulations to be prescribed by the Commissioner, with the approval of the Secretary. In the case of the leases the deductions allowed by this paragraph shall be equitably apportioned between the lessor and lessee.

Extract from Regulations 45:

Art. 220. Oil and gas wells.—Section 214 (*a*) (10) and section 234 (*a*) (9) provide that taxpayers who discover oil and gas wells on or after March 1, 1913, may, under the circumstances therein prescribed, determine the fai market value of such property at the date of discove y or within 30 days thereafter for the purpose of ascertaining allowable deductions for depletion. Before such valuation may be made the statute requires that two conditions precedent be satisfied, (1) that the fair market value of such property (oil and gas wells) on the date of discovery or within 30

days thereafter became materially disproportionate to the cost, by virtue of the discovery, and (2) that such oil and gas wells were not acquired as the result of purchase of a proven tract or lease.

Art. 220 (a). Discovery—Proven tract or lease—Property disproportionate value.—(1) For the purpose of these sections of the revenue act of 1918, an oil or gas well may be said to be discovered when there is either a natural exposure of oil or gas, or a drilling that discloses the actual and physical presence of oil or gas in quantities sufficient to justify commercial exploitation. Quantities sufficient to justify commercial exploitation are deemed to exist when the quantity and quality of the oil or gas so recovered from the well are such as to afford a reasonable expectation of at least returning the capital invested in such well through the sale of the oil or gas, or both, to be derived therefrom.

(2) A proven tract or lease may be a part or the whole of a proven area. A proven area for the purposes of this statute shall be presumed to be that portion of the productive sand or zone or reservoir included in a square surface area of 160 acres having as its center the mouth of a well producing oil or gas in commercial quantities. In other words, a producing well shall be presumed to prove that portion of a given sand, zone, or reservoir which is included in an area of 160 acres of land, *regardless of private boundaries*. The center of such square area shall be the mouth of the well, and its sides shall be parallel to the section lines established by the United States system of public land surveys in the district in which it is located. Where a district is not covered by the United States land surveys, the sides of said area shall run north and south, east and west.

So much of a taxpayer's tract or lease which lies within an area proven either by himself or by another is " proven tract or lease " as contemplated by the statute, and the discovery of a well thereon will not entitle such taxpayer to revalue such well for the purpose of depletion allowances, unless the tract or lease had been acquired before it became proven. And even though a well is brought in on a tract or lease not included in a proven area as heretofore defined, nevertheless it may not entitle the owner of the tract or lease in which such well is located to revaluation for depletion purposes, if such tract or lease lies within a compact area which is immediately surrounded by proven land, and the geologic

structural conditions on or under the land so inclosed may reasonably warrant the belief that the oil or gas of the proven areas extends thereunder. Under such circumstances the entire area is to be regarded as proven land.

(3) The "property" which may be valued after discovery is the "well." For the purposes of these sections the "well" is the drill hole, the surface necessary for the drilling and operation of the well, the oil or gas content of the particular sand, zone, or reservoir (limestone, breccia, crevice, etc.) in which the discovery was made by the drilling, and from which the production is drawn, to the limit of the taxpayer's private bounding lines, but not beyond the limits of the proven area as heretofore provided.

(4) A taxpayer to be entitled to revalue his property after March 1, 1913, for the purpose of depletion allowances must make a discovery after said date and such discovery must result in the fair market value of the property becoming disproportionate to the cost. The fair market value of the property will be deemed to have become disproportionate to the cost when the output of such well of oil or gas affords a reasonable expectation of returning to the taxpayer an amount materially in excess of the cost of the land or lease if acquired since March 1, 1913, or its fair market value on March 1, 1913, if acquired prior thereto, plus the cost of exploration and development work to the time the well was brought in.

Art. 221. Proof of discovery of oil and gas wells.—In order to meet the requirements of the preceding article to the satisfaction of the commissioner, the taxpayer will be required, among other things, to submit the following with his return: (*a*) A map of convenient scale, showing the location of the tract and discovery well in question and of the nearest producing well, and the development for a radius of at least 3 miles from the tract in question, both on the date of discovery and on the date when the fair market value was set; (*b*) a certified copy of the log of the discovery well showing the location, the date drilling began, the date of completion and beginning of production, the formations penetrated, the oil, gas, and water sands penetrated, the casing record, including the record of perforations, and any other information tending to show the condition of the well and the location of the sand or zone from which the oil or gas is produced on the date the discovery was claimed; (*c*) a sworn record of production, clearly proving the

commercial productivity of the discovery well; (*d*) a sworn copy of the records, showing the cost of the property; and (*e*) a full explanation of the method of determining the value on the date of discovery or within 30 days thereafter, supported by satisfactory evidence of the fairness of this value.

CHARGES TO CAPITAL AND TO EXPENSE IN THE CASE OF OIL AND GAS WELLS.

Regulations 45, article 223.—Such incidental expenses as are paid for wages, fuel, repairs, hauling, etc., in connection with the exploration of property, drilling of wells, building pipe lines, and development of the property, may, at the option of the taxpayer, be deducted as an operating expense or charged to the capital sum returnable through depletion. If the taxpayer elects to charge such well and development costs to operating expenses, the amount so charged can not be included in invested capital on which excess profits tax is computed, and the policy, once adopted, must be followed in subsequent years.

If in exercising this option the taxpayer charges these incidental expenses to capital sum, in so far as such expense is represented by physical property, it may be taken into account in determining a reasonable allowance for depreciation. The cost of drilling non-productive wells may, at the option of the operator, be deducted from gross income as an operating expense or charged to capital sum returnable through depletion and depreciation as in the case of productive wells. The taxpayer should adopt a consistent policy as to capitalizing or charging off cost of drilling non-productive wells.

Casing-head gas contracts have been construed to be tangible assets and their cost may be added to the capital sum returnable through depletion, following the rate set by the oil or gas wells from which the gas is derived, or, if the life of the contract is shorter than the reasonable expectation of the life of the wells furnishing the gas, the capital invested in the contract may be written off through yearly allowances equitably distributed over the life of the contract.

All oil produced during the taxable year, whether sold or unsold, must be considered in the computation of the depletion allowance for the taxable year. However, oil on hand at the

beginning and end of the year must, in computing net income, be inventoried at cost or estimated cost (including depletion or cost in the ground, plus lifting charges).

Where deductions for depreciation or depletion have either on the books of the taxpayer or in his returns of net income been included in the past in expense or other accounts, rather than specifically as depreciation or depletion, or where capital expenditures have been charged to expense in lieu of depreciation or depletion, a statement indicating the extent to which this practice has been carried should accompany the return.

DEPLETION FOR PAST YEARS NOT ALLOWED BY DEPARTMENT.

Where under the act of October 3, 1913, or of September 8, 1916, a taxpayer has not been allowed to make a deduction for the full amount of his depletion, the amount of such deficiency can not be carried forward and deducted in any later year. Depletion attaches to each unit of mineral or other property removed, and a taxpayer should make proper provision therefor in computing his net income. Under the Revenue Act of 1918 the amount recoverable through depletion will be the cost, or the value as of March 1, 1913, or within 30 days of the date of discovery, as the case may be, less proper allowance for the mineral or other property removed prior to January 1, 1918.

APPENDIX TO PART I.

SCHEDULES.

I. Schedule for Ascertaining Cost of Property as of any Specified Date.

1. Name of property.
2. Location of property.
3. Are you sole owner of property?
4. If not sole owner, your ownership interest therein.
5. Is property a leasehold?
6. (*a*) If so, name and address of lessor and lessee.
   (*b*) Date lease effective.
   (*c*) Date of expiration.
   (*d*) Royalty rate.
   (*e*) Bonus, either cash or property.

7. Date property was acquired.
8. (*a*) Manner of acquisition: (Purchase, trade, gift, etc.)
   (*b*) Amount paid in cash.
   (*c*) Amount paid in stock.
      (1) Par value of stock.
      (2) Actual cash value of stock.
      (3) How was this cash value established?
   (*d*) Amount paid in bonds.
      (1) Par value of bonds.
      (2) Actual cash value of bonds.
      (3) How was this cash value established?
   (*e*) Amount paid in other considerations.
      (1) What were the considerations?
      (2) State actual cash value of these considerations.
      (3) Manner of determining this cash value.
      (4) Name and address of party establishing value.
      (5) Append a copy of the report of the party establishing cash value of a résumé of his report.
   (*f*) Cash value of total consideration paid for property as established by you.

Map.

9. Map showing as of date of acquisition, location of the property, property boundaries, and location of all wells and other developments in this vicinity.

This map must be on a convenient scale, preferably of not less than 1/3180 or 2 inches to the mile for developed areas, and should show the following information for each tract as of date of acquisition:

(*a*) Wells producing.
(*b*) Wells temporarily suspended.
(*c*) Wells formerly productive but now abandoned.
(*d*) Wells completed to oil or gas sand or zone but non-productive.
(*e*) Wells abandoned before completion.
(*f*) Wells drilling.
(*g*) Area considered (1) producing, (2) proven, (3) highly probable, and (4) possible oil and /or gas lands, and (5) land worthless for oil and /or gas production. (Proven or proved oil or gas

land is that which has been shown by finished wells, supplemented by geologic data, to be such that other wells drilled thereon are practically certain to be commercial producers.)

In the case of a company owning more than one tract in a single pool or field, a field map folded to letter-size dimensions, say, 8 by 10 inches, if not too cumbersome, may be sent, and each tract designated by a letter or some other convenient symbol.

Land Data.

10. Area in acres as of date of acquisition of—
    (*a*) Fully developed oil or gas territory.
    (*b*) Proven oil or gas territory.
    (*c*) Highly probable oil or gas territory.
    (*d*) Possible oil or gas territory.
    (*e*) Territory worthless for oil or gas production.
    (*f*) Total acreage.
11. Name and address of the party making land classification as covered in questions 9 and 10.

Well Data.

12. Furnish the following information as of date of acquisition:
    (*a*) Number of wells producing.
    (*b*) Number of wells abandoned or temporarily suspended.
    (*c*) Number of wells drilling.
    (*d*) Number of new locations yet remaining undrilled on proven territory.
13. (*a*) Number of producing oil and /or gas sands proven on property.
    (*b*) Designation of the different sands, with the average thickness of each and average depth from surface to the top of each sand.
    (*c*) Any other information regarding conditions in wells which might be used to classify the wells in groups.
    (*d*) List of wells as of date of acquisition, showing the following information regarding each:
        (1) Number or letter by which each is designated.
        (2) Date of beginning drilling.
        (3) Date of beginning of production.

(4) Date abandoned.
(5) Initial daily production.

14. Submit table showing—
(*a*) Production of tract by calendar years from the beginning of production to date of acquisition, with average number of wells producing each year.
(*b*) The same information for calendar years subsequent to date of acquisition.
(*c*) Amount received each year for production mentioned in (*a*) and (*b*).
(*d*) Average price per barrel received for oil, given by years since production began.
(*e*) Total production prior to date of acquisition, in barrels.
(*f*) Total production subsequent to date of acquisition, in barrels.
(*g*) Total amount received for production mentioned in (*e*) and (*f*).
(*h*) If the tract or wells have been producing for less than two years, monthly production figures must be furnished.

15. (*a*) Production of individual wells, by calendar years from beginning of production to date of acquisition, if such data are available.
(*b*) Same information for period subsequent to date of acquisition.
(*c*) If, through any cause, it is impossible to give yearly production records by individual wells, state the reasons why this information is not available.

Oil and Gas Reserves in Property.

16. (*a*) What was the estimated total number of units of oil and/or gas in the property on date of acquisition?
(*b*) How was this estimate made?
(*c*) Append a copy of the appraisal from which the estimates were derived or append a résumé of the calculations utilized in making the estimate.
(*d*) Give name and address of party making the estimate.

17. (*a*) State range in specific gravity of oil recovered.
(*b*) State average specific gravity oil delivered.

(*c*) If more than one grade delivered, give percentage of each for a year of acquisition.

Casing-head Gas.

18. Submit table showing—
   (*a*) Quantity of casing-head gas produced by months from date of first production to date of acquisition.
   (*b*) Quantity of casing-head gas produced by months for period subsequent to date of acquisition.
   (*c*) Average number of wells contributing to this production each year.
   (*d*) In case the gas is sold, give the amount received each month for gas mentioned in (*a*) and (*b*).
   (*e*) Quantity of gasoline in gallons recovered each year from casing-head gas, mentioned in (*a*) and (*b*).
   (*f*) Amount received each month for gasoline mentioned in (*e*).
   (*g*) Average price per gallon received for gasoline mentioned in (*e*).
   (*h*) Production of oil by months for the wells from which this casing-head gas is taken. Give this information by individual wells if possible; if not, then by tracts with number of wells producing each month. When monthly records are not available give data by years.

Gas-well Data

19. Submit table giving list of gas wells as of date of acquisition, and showing—
   (*a*) Number or letter by which each is designated.
   (*b*) Date of beginning drilling.
   (*c*) Date of beginning production.
   (*d*) Date of abandonment.
   (*e*) Initial open flow capacity.
   (*f*) Initial closed rock pressure.
   (*g*) Closed rock pressure as of date of acquisition.

Gas-production Data.

20. Submit table showing—
    (*a*) Gross production (of gas) by calendar years, from beginning of production to date of acquisition, with number of wells producing each year.
    (*b*) Same information for years subsequent to date of acquisition.
    (*c*) Amount of money and cash value of any other consideration received each year for production mentioned in (*a*) and (*b*).
    (*d*) Average price per thousand cubic feet of gas, by years from beginning of production.
    (*e*) Total yield from beginning production to date of acquisition, in cubic feet.
    (*f*) Total yield from beginning production to date, in cubic feet.
21. Production of individual wells by calendar years for all wells to end of taxable year.
22. (*a*) Average rock pressure in September of each year during which production has been maintained.
    (*b*) Rock pressure of individual or test wells on tract. (Answers should be attached as a separate statement giving all rock pressures measured during life of the well or property. The method used in measuring pressures should be mentioned.)

Physical Property.

23. Does the cost of property as given in 8 (*f*) of this schedule include any amount for plant or other physical property or for the value of the land for any other purpose than that as container of oil and gas?
24. If it does, what amount is applicable solely—
    (*a*) To the value of the oil and gas contents?
    (*b*) To the surface or agricultural value of the land or its value for anything other than for its oil and gas contents?
    (*c*) To plant or other physical property?

25. Give general inventory as of date of acquisition of the physical property mentioned in 24 (*c*) with the following information regarding each type:
   (*a*) Year originally acquired.
   (*b*) Original cost.
   (*c*) Depreciation sustained to date of acquisition.
   (*d*) Estimated cost as of date of acquisition.

II. Schedule for the Valuation of Property as of any Specified Date.

Introduction.—In actually determining the fair market value of any property as of any specified date it will be necessary in most instances to require very full data regarding the property in order that no factors having a bearing on the value may be overlooked. The following information as of the specified date of appraisal will usually be required of the taxpayer in order to substantiate his appraisal.

NOTE.—"Date of appraisal" is the specified date as to which the valuation is set up and is not the date on which the appraisal is made.

1. *Description of the property.*
   (*a*) A legal description of the property, including its location in section (or farm), township, range, county, and State.
   (*b*) Whether or not the taxpayer is the sole owner; and if not, his ownership interest therein and the names and addresses and ownership interest of each of other joint owners.
   (*c*) Whether the property is a leasehold; if so, the name and address of the lessor and lessee.
   (*d*) The date lease was effective.
   (*e*) Date of expiration.
   (*f*) Royalty rate.
   (*g*) Bonds, either cash or property.
   (*h*) Any unusual terms of lease.
2. *Date of acquisition.*—The date the property was acquired.
3. *Manner of acquisition and cost.*
   (*a*) The manner of acquisition of the property, whether by purchase, trade, gift, etc.

(*b*) The amount of the consideration paid, such as cash, stock, bonds, etc., and the cash value of these, and how this cash value was determined.

4. *Map of property.*—A map of the property on a convenient scale, preferably not less than 2 inches to the mile, showing as of date of appraisal—
   (*a*) The producing, suspended, or abandoned, and drilling wells, and
   (*b*) The area of the tract which is considered producing, proven, highly probable, possible, or worthless oil or gas land.

   In the case of a taxpayer owning more than one tract in a single pool or field, a field map may be substituted for maps of each tract, the tracts or leases being designated by letter or some other symbol.
5. *Land data.*—A statement as to the number of acres considered fully developed, proven, highly probable, possible, or worthless oil or gas territory, including the total acreage, and the name and address of the party making such classification.
6. *Well data.*—
   (*a*) Information as to the number of wells producing, abandoned, or suspended, drilling and the number of locations remaining undrilled on proven territory.
   (*b*) The number and designation of the oil or gas sands proven on the property, with their average thickness and the average depth from the surface of the top of each sand.
7. *Individual well data.*—The following information regarding the individual wells:
   (*a*) The number of the well.
   (*b*) Date began drilling.
   (*c*) Date began producing.
   (*d*) Date abandoned.
   (*e*) Initial daily production.
8. *Production data.*
   (*a*) The production of each tract by calendar years for the periods prior to and subsequent to the date of appraisal.

(*b*) The average number of wells producing each year.
(*c*) The amount received each year for the production.
(*d*) The average price per barrel received each year.
(*e*) The total production prior to and subsequent to date of appraisal.
(*f*) The total amount received prior to and subsequent to the date of valuation.

Where production figures of individual wells are available, give the records for all years from the beginning of production to the date of valuation, and for the years subsequent thereto. In the case of properties yielding production for a period of less than two years, the above data should be given by months instead of years.

9. *Oil and gas reserves.*
   (*a*) The estimated total number of units of oil or gas in the property as of the date of appraisal. (Many operators are prone to say it is impossible to estimate the quantity of oil or gas under any tract—obviously it is impossible to determine this exactly but *it can be done with reasonable accuracy* in most instances.)
   (*b*) How this estimate was made.
   (*c*) The name and address of the party making the estimate and a copy or résumé of his report.
10. *Specific gravity.*
   (*a*) The range in specific gravity of the oil recovered.
   (*b*) The average specific gravity of the oil delivered, and, if more than one grade is delivered, the percentage of each delivered during the year covered by the appraisal.
11. *Casing-head gas.*—The following information by months:
   (*a*) The quantity, in thousands of cubic feet, produced prior to and subsequent to the date of appraisal.
   (*b*) The number of wells producing this gas.
   (*c*) The amount received for the gas, if such was sold direct.
   (*d*) The quantity, in gallons, of gasoline made.
   (*e*) The amount received for this gasoline.
   (*f*) The average price per gallon.

(*g*) The production of oil by months for the wells yielding the gas covered by this paragraph.

12. *Gas properties.*—In the case of gas properties the well data should include:

(*a*) The number of each well.
(*b*) Date began drilling.
(*c*) Date began producing.
(*d*) Date abandoned.
(*e*) Initial daily capacity.
(*f*) The initial closed rock pressure.
(*g*) Present closed rock pressure.

The production data are to be given by calendar years prior to and subsequent to date of appraisal.

(*a*) Number of wells producing.
(*b*) The value of the product and the average price per thousand feet.
(*c*) The total yield (1) prior to and (2) subsequent to the date of appraisal.
(*d*) The gross production of individual wells by calendar years to date.
(*e*) The average rock pressure during September of each year during which production has been maintained, and as many records as possible of the rock pressure of individual or test wells.

Direct Methods of Determining Value.

13. The points to be considered directly in the establishment of a fair market value must include the method by which this value was ascertained.

(*a*) Whether established by cost.
(*b*) By comparison with values established by actual sales of similar properties.
(*c*) By appraisal.
(*d*) By assessed value.
(*e*) By any other method.

14. If the value is based upon the values of other properties, as established through the transfer of the properties, details regarding each transaction will be necessary. Furthermore, it will be advisable to give information

regarding any bona fide transactions in oil or gas properties in the region of the tract under appraisal about which the taxpayer is able to obtain data, this information to include as many of the items called for in connection with the valuation of the property itself as it is possible to secure.

15. If the value is established by appraisal give—
    (*a*) The name and address of the party making the appraisal.
    (*b*) His connection, if any, with the taxpayer or with any of his associates or associated companies.
    (*c*) The date of making the appraisal.
    (*d*) A copy of the appraisal or a résumé.
16. If the value is established by assessed valuation, the following should be given:
    (*a*) Name and address of official making the assessment.
    (*b*) Whether it was assessed at its actual cash value or at a portion of its cash value.
    (*c*) What its total assessed valuation was in the year in which the appraisal was made.
    (*d*) What portion of the assessed valuation represents real property?
    (*e*) What portion represents personal property.
    (*f*) What portion of the assessed value of the real property represents oil or gas in the ground?
17. If the values are established by any other method than the above a full description of the method used and conclusions reached should be given.
18. If the valuation of the property includes any amount for plant or other physical property, or for the surface or agricultural value of the land, or the value of the land for any other purpose than as a container of oil and gas the value should be segregated under the headings:
    (*a*) Value of oil and gas contents.
    (*b*) Values for anything other than for oil and gas contents.
    (*c*) Value of plant or other physical equipment.
19. An inventory of the physical equipment as of the date of appraisal should be given, together with the following information regarding each type of property:
    (*a*) When the equipment was first used.

(*b*) Its cost.
(*c*) Its total depreciation up to the date of appraisal.
(*d*) Its value as of the date of appraisal.
(*e*) Depreciation by calendar years for each year subsequent to the date of appraisal.

The classification of physical equipment will be found under the chapter on depreciation, page 78 of this Manual.

Indirect Methods of Determining Value.

20. The book value of the total assets on the date of valuation exclusive of oil or gas in the ground.
21. (*a*) The number, par value, and cash value of the shares of capital stock issued and outstanding on the date of appraisal.
    (*b*) Whether or not these outstanding shares were fully paid.
    (*c*) Information as to what stock exchange or "curb" market the stock or bonds were listed on, or dealt in, on or about the date of appraisal; or if the stocks were not quoted publicly, particulars regarding private transactions in the stock or bonds on or about the date of appraisal.
22. Total permanent indebtedness classified as bonds, notes, contracts, etc., and what the quoted value of these securities was or any particulars regarding public or private transactions which would tend to establish their value.
23. The prevailing average royalty rates stipulated in leases taken within a year of the date of appraisal in the district in which the property is located.
24. Copy of the report of the stockholders of the company for each of the fiscal years preceding and following the date of appraisal.
25. So far as known, the names of the parties to any litigation in which the value of the oil and/or gas properties in the particular region of the property under discussion, or of a partnership interest or other interest therein, or of stock in a corporation owning or operating the

same, was involved; also, the name of the court or courts in which such litigation was conducted.

26. If the value of the oil and/or gas wells in the particular region of the property, or of any interest or stock therein has been involved in any partnership accounting known, a statement regarding such accounting should be given.
27. If anyone interested in the oil and/or gas wells in the particular region of the property under discussion or as owner, operator, or member of a partnership, or stockholder in a corporation owning or operating the same died on or about the date of appraisal, give the name, number of shares held, the approximate date of death, the residence at time of death, and the name and location of the court in which the estate was administered, and the name and address of the administrator.
28. In addition to the above the taxpayer is requested to submit any other evidence, facts, statements, etc., which he desires to have considered in the determination of the value as of the date of appraisal.

III. Schedule for Proof of Discovery

Introduction.—In order to prove to the satisfaction of the Commissioner that a bona fide discovery of oil or gas in commercial quantities has been made, the taxpayer will be required, among other things, to submit the following, under oath:

1. *Description of the property.*
   (*a*) A legal description of the property, including its location in section (or farm), township, range, county, and State.
   (*b*) Whether or not the taxpayer is the sole owner, and if not, his ownership interest therein, and the names and addresses and ownership interest of each of the other joint owners.
   (*c*) Whether the property is a leasehold; if so, the name and address of the lessor and lessee.
   (*d*) The date lease was effective.
   (*e*) Date of expiration.
   (*f*) Royalty rate.

(*g*) Bonus, either cash or property.
(*h*) Any unusual terms of lease.

2. Date of acquisition.
3. The location of the nearest producing well to the discovery well on the date discovery is claimed.
4. *Map of property.*—A map of the property on a convenient scale, preferably not less than 2 inches to the mile, showing, as of the date of discovery,
   (*a*) The location of the tract and of the discovery well in question and in addition the development in the field for a radius of approximately 3 miles from the well in question;
   (*b*) The producing, suspended or abandoned and drilling wells; and
   (*c*) The areas which are considered producing, proven, highly probable, possible, or worthless oil or gas land.
5. A certified copy of the log of the discovery well, showing:
   (*a*) The location.
   (*b*) Date drilling began, date of completion and the beginning of production.
   (*c*) The formations penetrated; the oil, gas, and water sands penetrated; the casing record, including the record of perforation and any other information tending to show the condition of the well and the location of the sand of sands from which the oil or gas came on the date the discovery was claimed.
6. The logs of enough other wells drilled prior to the date of the completion of the discovery in the vicinity of the discovery well to convince the Commissioner that the pool, field, structure, sand, or zone, discovery of which is claimed, was not known prior to the so-called discovery.
7. A sworn record clearly proving the commercial productivity of the discovery well. This record must cover a period of not less than 30 days and, if possible, should include the production of the entire period by months from the date of discovery to the end of the first year.
8. In the case of the discovery being made within 3 miles of producing wells, the production data from enough

wells within this area to indicate the average productivity of the wells drilled prior to the date of drilling the discovery well:

9. The specific gravity of:
   (*a*) The oil recovered from the discovery well.
   (*b*) Oil produced by adjacent wells which were producing at the time of the drilling of the discovery well.
10. The following information regarding wells drilled on the same tract or lease as the discovery well prior to and subsequent to the date of the discovery:
   (*a*) Number of well.
   (*b*) Date of beginning drilling.
   (*c*) Date of beginning production.
   (*d*) Date abandoned.
   (*e*) Initial daily production.

   And in the case of wells drilled prior to the date of discovery—
   (*f*) Copy, of the log of the well, including the formation penetrated.
   (*g*) The casing record and any other information tending to show the condition of the well on the date discovery was claimed in the discovery well.
11. Any other evidence, facts, statements, etc., which the taxpayer desires to have considered as proving that the so-called discovery is bona fide and that the pool, field structure, sand, or zone, discovery of which is claimed, was not known prior to the date of discovery.

IV. Schedule for Depletion.

With respect to each property producing oil and/or gas during the taxable year for which the return under consideration was filed give the following facts:

1. Description of property.
2. Value (exclusive of physical properties) as of March 1, 1913, or its cost if acquired subsequent to that date.
3. Estimated quantity of oil and/or gas in ground as of March 1, 1913, or at date of acquisition if secured subsequent to March 1, 1913.
4. Make tabulation showing:

(*a*) Capital sum returnable through depletion at beginning of year.
(*b*) Capital returnable through depletion added during year.
(*c*) Total capital sum against which depletion for year is chargeable ((*a*) plus (*b*)).
(*d*) Estimated quantity of recoverable crude oil in ground at beginning of year, in barrels of 42 gallons.
(*e*) Production for year in barrels of 42 gallons.
(*f*) Unit cost of recoverable product ((*c*) divided by (*d*)).
(*g*) Amount of depletion sustained during year ((*f*) multiplied by (e)).

V. Schedule for Depreciation.

With respect to each tract on which there is physical property mentioned in the return under consideration, give the following facts:

1. Description of property.
2. Value of physical properties as of March 1, 1913, or their cost, if acquired subsequent to that date.
3. Make tabulation showing:
   (*a*) Capital sum returnable through depreciation at beginning of year.
   (*b*) Capital returnable through depreciation added during year.
   (*c*) Total capital sum against which depreciation for year is chargeable (*a*) plus (*b*).
   (*d*) Amount of depreciation sustained during year.

VI. Schedule for the Proof of Bona Fide Sale.

Introduction.—To prove that the sale consummated by the taxpayer is actually bona fide, he will be required to furnish a sworn statement, including the following:

1. *Description of the property.*
   (*a*) A legal description of the property, including its location in section (or farm), township, range, county, and State.
   (*b*) Whether or not the taxpayer is the sole owner, and if

not, his ownership interest therein, and the names and addresses and ownership interest of each of the other joint owners.

(*c*) Whether the property is a leasehold; if so, the name and address of the lessor and of the lessee.

(*d*) The date lease was effective.

(*e*) Date of expiration.

(*f*) Royalty rate.

(*g*) Bonus, either cash or property.

(*h*) Any unusual terms of lease.

2. Date of disposal of property.

3. *Manner of disposal of the property.*—Whether by sale, trade gift, etc.

4. (*a*) The amount received in cash, stock, bonds, and other considerations.

(*b*) The par value of the stock, bonds, or other considerations.

NOTE.—If the "unit-cost" method of computing depletion was not used in computing the depletion allowance for the various years mentioned in the above table, state what method was used in calculating the depletion, and give a complete résumé of the calculations, so that the Commissioner may arrive at an intelligent conclusion as to whether or not the depletion allowance claimed for the year was equitable and based on the actual production of that year.

(*c*) The actual cash value of the stock, bonds, or other considerations on the date of disposal of the property.

(*d*) How these cash values were established.

(*e*) The name and address of the party determining or establishing these values.

5. Total cash value of all considerations received by the taxpayer for the property.

6. (*a*) The name and address of the party to whom the property was transferred.

(*b*) The connection, business or other, if any, between parties to the transfer.

7. The taxpayer disposing of the property will be required, under oath, to state whether or not the price at which the property was sold was fixed for the purpose of a bona fide purchase and sale by which the property

passed to an owner in fact as well as in form different from the vendor. No fictitious nor inflated sale price will be permitted to form the basis for the price established for this schedule.

8. Any evidence, facts, statements, etc., which the taxpayer desires to have considered as a proof in the determination of the bona fide character of the transaction.

VII. Schedule for Computation of Profits or Loss from Sale of Capital Assets.

With respect to each property disposed of during the year, furnish the following information:

1. Description of property.
2. Date of disposal of property.
3. Manner of disposal of the property (sale, trade, gift, etc.).
4. Amount received in cash.
5. Amount received in stock:
   (*a*) Par value of stock.
   (*b*) Actual cash value of stock.
   (*c*) How was this cash value established?
6. Amount received in bonds:
   (*a*) Par value of bonds.
   (*b*) Actual cash value of bonds.
   (*c*) How was this cash value established?
7. Amount received in other considrations:
   (*a*) What were these considerations?
   (*b*) Actual cash value of these considerations.
   (*c*) Manner of determining this cash value.
   (*d*) Name and address of the party determining this value.
8. Cash value of all considerations received for property.
9. Value of property as of March 1, 1913, or its cost if acquired subsequent to that date.
10. Total of all additions to capital returnable through depletion added subsequent to March 1, 1913, or subsequent to date of acquisition if property acquired subquent to March 1, 1913.
11. Total of all additions to capital returnable through depreciation added subsequent to March 1, 1913, or subse-

quent to date of acquisition if acquired subsequent to March 1, 1913.

12. Gross value of property as of date of disposition. (Total 9, 10, and 11.)
13. Total depletion sustained during period from March 1, 1913, or from date of acquisition if acquired subsequent to March 1, 1913, to date of disposition of property.
14. Total depreciation sustained during period from March 1, 1913, to date of disposition of property.
15. Net value of property as of date of disposition of property (12 less the sum of 13 and 14).
16. Profit or loss sustained from disposition of property (difference between 8 and 15).

VIII. Schedule for Proving that the Principal Value has been Demonstrated by Prospecting or Exploration and Discovery Work Done by the Taxpayer.

Introduction.—In the case of a bona fide sale of oil or gas properties it will be necessary, in order to secure the benefits of sections 211b and 337 of the Revenue Act of 1918, which limits the portion of the surtax imposed by said act attributable to such sale to a sum not to exceed 20 per cent of the selling price of such property or interest, to satisfy the commissioner that the principal value of the property has been demonstrated by prospecting or exploration and discovery work done by the taxpayer by submitting the following among other data:

1. *Description of the property.*—
   (*a*) A legal description of the property, including its location in section (or farm), township, range, county, and State.
   (*b*) Whether or not the taxpayer is the sole owner, and if not, his ownership interest therein, and the names and addresses and ownership interest of each of other joint owners.
   (*c*) Whether the property is a leasehold; if so, the name and address of the lessor and lessee.
   (*d*) The date lease was effective.
   (*e*) Date of expiration.
   (*f*) Royalty rate.

(*g*) Bonus, either cash or property.
(*h*) Any unusual terms of lease.

2. *The value of the property immediately prior to the date of beginning the prospecting or exploration and discove y work done by the taxpayer leading to the discovery claimed.*—(This may be established through filling out Schedule II as of the specified date.)
3. *The proof that a discovery has been made.*—(To furnish this proof the taxpayer will be required to fill out Schedule III.)
4. *The value of the property at any specified data within a reasonable time after the discovery was made.*—(This value may be established by filling out Schedule II for the specified data.)
5. Any evidence, facts, statements, etc., which the taxpayer desires to have considered as showing that the principal value of the property has been demonstrated by prospecting or exploration and discovery work done by himself.

PART II.

ESTIMATE OF DEPRECIATION OF EQUIPMENT USED IN THE OIL AND GAS INDUSTRY.

PREFACE TO PART II.

This chapter is a condensation and summarization of the conclusions of a committee appointed to investigate and standardize depreciation allowances in the case of oil and gas properties. It is prepared to meet the questions of taxpayers as to what is a reasonable allowance for depreciation in the case of oil and gas properties. In preparing the figures of rates of depreciation, reports from some of the larger companies were reviewed and the opinions of various individuals closely associated with the industry were obtained. Over 5[illegible] companies and individuals were canvassed in this work and the conclusions were reached by considering the company practices as well as taking into account the experience of the members of the committee and the precedents and practices of the Treasury Department.

The percentages and tables included in this paper are intended as a *suggestion* for the guidance of the taxpayer in calculating his just tax. The percentages are neither maximum nor minimum rates. They are *not to be applied indiscriminately to specific property,* and the Internal Revenue Bureau is in no way committed to accept allowances based upon them. Every claim for deduction must be accompanied by a detailed statement of the facts upon which such claim is based.

Each class of equipment is shown in detail and as a class, with the suggestion that an average life of the class be used rather than going into the details of every part.

The average years of useful life of the various classes is shown in the summary sheet and a suggestion for charging out annual percentages to conform to the depreciation as it actually occurs.

It must be borne in mind that it is not possible to make standard rules or formulæ to cover all conditions in this business.

Although different rates may reasonably be applied in different

parts of the country, the average rates for each locality have not been included here, as it is believed that the variation of such rates from the general average is so slight as to be practically negligible in most instances. Whenever the life of the property is materially shorter than that called for in this schedule, a special rate may be claimed, or the difference may be made up by replacements chargeable to the maintenance accounts. In the case of some of the Gulf coast districts, portions of the pipe lines are eaten out in five or six years. These repairs are rightly a replacement and chargeable to maintenance or operating accounts.

Depreciation deductions are to be charged to a reserve fund, and are in addition to any regular charge for repairs and operating maintenance.

No consideration has been given exceptional cases where premature failure of supply or market may materially reduce the given life of the facility. Such cases are necessarily exceptional and will receive special consideration, as provided for in the regulations. (See Regulation 45, Art. 225.)

CLASS A, NO. 1.—DRILLING EQUIPMENT.

This includes engines, boilers, rig irons, and portable derricks.

It is recommended that four years' life be allowed to equipment as a whole, depreciated at the following rate

	Per Cent.
First year	40
Second year	25
Third year	15
Fourth Year	10
	90
Salvage	10
	100

Permanent derricks, rig irons, boilers, and engines left at the well are included under " Well equipment."

Drilling tools (cable and rotary), and fishing tools are included under " Tools "—Class A–No. 5.

CLASS A, NO. 2.—WELL EQUIPMENT.

As most equipment of a producing well *has no separate value apart from the well*, it is suggested that all wells and their equip-

ment be depreciated at the same rate as the wells are *depleted*, using the same curve rate for both or where the life of the physical equipment is greater than the life of the deposit, then the depreciation rate of the physical equipment will be governed by the reasonable expectation of the life of the deposit.

When the life of the equipment is shorter than the life of the well, replaced equipment should be charged against maintenance and operation.

This method proved satisfactory in the appraisement of the Independent Oil Producers Agency of California, embracing some 130 companies, and is generally acceptable to all operators who have been consulted in the matter.

CLASS A, NO. 3.—DEHYDRATORS.

These are either of electric, pipe, or tank type. The life of the pipe and tank dehydrators is very erratic as these burn out quickly with practically no salvage. It is recommended that this type of equipment have a straight line depreciation as follows:

	Life.	Depreciation per Year.
	Years.	Per Cent.
Electric	5	20
Pipe	2	50
Tank	2	50

CLASS A, NO. 4.—TANKS.

The following depreciation rate for tanks is recommended:

	Life.	Per Cent.
	Years.	
Steel, 5,000 to 55,000 barrels	20	5
Steel, 2,500 to 5,000 barrels	12	$8\frac{1}{3}$
G. I., 500 to 2,500 barrels	12	$8\frac{1}{3}$
G. I., less than 500 barrels	8	$12\frac{1}{2}$
Wood	5	20
Movable tanks:		
G. I., 500 to 2,500 barrels	9	$11\frac{1}{9}$
G. I., less than 500 barrels	6	$16\frac{2}{3}$
G. I., water tanks, 500 to 2,500 barrels	8	$12\frac{1}{2}$
G. I., water tanks, less than 500 barrels	5	20

These results may be used for all classes of service—that is, oil producing, refineries, etc.

CLASS A, NO. 5.—TOOLS.

This includes standard, rotary, and fishing tools. While rotary equipment may be shorter lived, it is, in general, offset by the standard tool equipment which will have a life of at least four years in many cases.

Owing to the excessive wear and tear and losses on such equipment an average life of three years is recommended, using an annual depreciation of $33\frac{1}{3}$ per cent.

CLASS A, NO. 6.—TRANSPORTATION EQUIPMENT.

All transportation equipment, such as motor trucks, autos, wagons, horses, and harness, can be placed at a three-year life or an annual depreciation of $33\frac{1}{3}$ per cent.

In fact, the average life of automobiles is less than three years. The percentages of cost for horses, harness, and wagons is such that the whole can be made one class with three years' life and consider no salvage.

CLASS A, NO. 7.—WATER PLANTS.

Considering the water well, pump, steam power, gas and oil power, electric power as a class, they may be given a useful life of approximately 10 years, which allows a straight depreciation of 10 per cent.

CLASS A, NO. 8.—ELECTRIC EQUIPMENT.

In considering electrical equipment, one may include the separate items of generators, various size motors, transformers, wiring (both indoor and outdoor), power lines, and switchboard.

As oil-well motors are not suitable for other uses and as the class of wiring usually done on leases is not up to utility company standards, it is recommended that a combined life on electric equipment be placed at 10 years, or an annual depreciation of 10 per cent.

CLASS A, NO. 9.—MACHINE SHOP.

In covering machine shop there is included wood buildings, power tools, blacksmith tools, small hand tools, shafting, and shop power, which will, on an average, have a seven-year life or a depreciation rate of $14\frac{2}{7}$ per cent. The smaller hand tools, of course, may have a life of not more than two years, but their cost is not important and the depreciation rate is lowered by the longer life of more expensive items, such as power tools, wood buildings, shafting, and shop power.

CLASS A, NO. 10.—BUILDINGS.

Buildings are grouped into four general classes:

No. 1. Wood, which includes small dwellings, small outhouses, small warehouses, small power plants, and small platforms which are built on the ground. These have an average life of 10 years, which allows a depreciation rate of 10 per cent.

No. 2. Frame buildings, placed on brick or concrete foundation with siding and shingle or patent roof-painted, have an average life of 15 years or a straight line depreciation of $6\frac{2}{3}$ per cent.

No. 3. Corrugated iron siding, renewable, has a life of six years or a depreciation rate of $16\frac{2}{3}$ per cent

No. 4. Concrete, brick, and steel frame have an average life of 25 years or an annual depreciation rate of 4 per cent.

The permanent buildings may outlast the remainder of the plant; hence, no salvage value. Gulf Coast fields may claim shorter life on account of salt-air conditions.

CLASS B.—PIPE LINES.

Pipe lines are subdivided into main line, pump stations (which include all equipment such as engines, pumps, boilers, etc.), auxiliary equipment, buildings, telephone and telegraph, and terminal facilities.

It is recommended that—

Mains 6 inches in diameter or over be based on a 20-year life or an annual depreciation of 5 per cent.

Mains under 6 inches diameter be based on a 16-year life or an annual depreciation of $6\frac{1}{4}$ per cent.

Gathering lines be based on a 10-year life or an annual depreciation of 10 per cent, with a salvage of 10 per cent.

Pump stations, including all equipment, telephone lines, and terminal facilities a life of 10 years, or an annual depreciation of 10 per cent.

These conclusions were reached after carefully considering detailed data in which it was decided that pipe lines could be grouped into the subdivisions given above.

The subject of electrolysis in pipe lines has been investigated and the losses have proved to be very small and negligible in comparison with the amounts invested, so far as making any special allowances in depreciation.

Below is given the result of a pipe line 220 miles long, having 16 stations and costing $3,906,668.

		Per Cent of Total Life in—		Weight.
		Cost.	Years.	
Right of way	$83,176	2.2	20	0.44
Ditching	497,358	12.7	*20	2.54
Pipe	1,323,901	33.9	20	6.78
Steel storage	426,047	10.9	20	2.18
Buildings	246,651	6.3	20	1.26
Total	2,577,133	.....	.....	.....
Machinery:				
Pumps	260,108	6.7	14	.94
Boiler	136,356	3.5	10	.35
Heaters	30,341	.8	10	.08
Miscellaneous (freight, etc.)	88,937	2.3	8	.18
Total	515,742	.....	.....	.....
Wiring	8,060	.2	10	.02
Fittings	151,725	3.9	7	.27
Commissary	270,782	6.9	10	.69
Telephone lines	85,905	2.2	10	.22
Spurs, loading racks, etc	14,276	.4	5	.02
Sundries (tools, paints, water wells, etc., superintendence supervision)	283,045	7.2	5	.36
Total	1,329,535	100.1	.....	†16.33
Grand total cost	3,906,668			

* Same as pipe. † Average life.

CLASS C.—TANK CARS.

This class of equipment is of very stable construction, and it would appear that the maximum 20-year life can be accorded and a 5 per cent per annum depreciation established.

CLASS C.—REFINERIES.

In order to arrive at a depreciation figure for the refinery as a whole, it is necessary to determine the relative investment in each item of equipment as compared to total investment. The various items have been grouped into classes that have about the same rate of depreciation, and the depreciation for the whole plant calculated by multiplying each item by its rate of depreciation.

Refineries were divided into two classes, skimming plants and complete refineries—that is, refineries equipped with lubricating plants (but not having cracking plants). Figures for relative investment in each class of equipment were obtained from reports on valuation of refineries and from our own estimates.

CALCULATED DEPRECIATION FOR WHOLE REFINERY.

(*a*) Complete Refinery.

	Per Cent of Total Investment.	Rate of Depreciation.	Product.
Equipment:	Per Cent.	Per Cent.	Per Cent.
Distilling equipment (stills, condensers, agitators, etc.)	25	15	3.8
Power plant (boilers, engines, electrical equipment, etc.)	15	10	1.5
Buildings	10	5	.5
Storage (all kinds)	25	8	2.0
Pipes and fittings	10	12	1.2
Lubricating plant (filters, presses, chillers, grease plant, etc.)	10	10	1.0
Miscellaneous (. . . loading racks, machine shop, laboratory, etc.)	5	10	.5
Depreciation on refinery as a whole	.....	.....	10.5

(*b*) Skimming Plant.

	Per Cent.	Per Cent.	Per Cent.
Distilling equipment	35	15	5.3
Power plant	10	10	1.0
Buildings	5	10	.5
Storage	35	8	2.8
Pipes and fittings	10	12	1.2
Miscellaneous	5	10	.5
Depreciation on refinery as a whole	.....	.....	11.3

Refineries can also be classed according to their location into three general classes and should be given rates of depreciation accordingly. The three classes and suggested relative depreciation are as follows:

	Useful Life.	Depreciation Rate.
	Years.	Per Cent.
Well-constructed refinery plants located on the Atlantic coast or Gulf coast or at points that are assured of a supply so long as there is production east of the Rocky Mountains or from Mexico.....	20	5
Refinery plants of good construction located on trunk pipe lines or where a supply of crude is assured for several years.....	10	10
Skimming plants and small refineries of poor construction or located at points where the supply of crude is not assured for a long period of time.....	6	16⅔

It is suggested that the last named be depreciated according to the decline curve of the oil field supplying the oil.

The estimates of the total depreciation were based on what was considered the normal life of the plant, and no conditions that were purely local were taken into consideration. However, in making any depreciation charge the relation of the location must be taken into account. Such things as the supply of raw material, removal of market, climatic conditions, soil conditions, and the nature of the raw material are points brought out by local conditions.

Plants situated on pipe-line terminals and those on the seaboard that can be fed by tankers and pipe lines have an advantageous position. Plants in the midst of an oil field relying solely on that field for crude supply have a length of life depending on the life of the field. Plants on pipe lines controlled completely or in part by the company owning the plant are in much better shape than those dependent on a rival company for their supply of crude.

A plant is subject to the removal of its market in whole or in part when it is situated a great distance from that market and is confronted with a new plant or competitor adjacent to the market that is able to undersell the products of the distant plant. The foreign market may be completely removed through the growth of new oil fields and competitive tariff conditions.

Any abnormal rate of depreciation due to the chemical nature of the soil causing ironwork to deteriorate rapidly must be con-

sidered. Conditions of high humidity shorten the life of ironwork and brickwork.

High sulphur crudes cause stills and condensers to deteriorate rapidly. Crudes containing salt, other solid or colloidal matter and those carrying a high content of water and foreign matter cause a shorter life for general refinery equipment.

An agreement must be reached between the Treasury Department and the refiners in cases for special districts as to just how much extra depreciation they should be allowed for a condition that is peculiar to their territory.

The total general depreciation that is allowed takes in the skimming plants and so-called complete refineries that have a lubricating plant. For plants that have a complete refinery and in addition cracking plant, certain extra depreciation charges must be allowed. In many cases the cracking plant is as much as one-tenth the total plant investment and should be given a shorter life than the average plant's life.

CLASS D.—SALES OR MARKETING EQUIPMENT.

Sales or marketing equipment is summarized in the following table:

	Life for Depreciation.	Annnual Depreciation Rate.
Tankers: Where such have been bought or built during the war period, that such cost be written off to $125 per D. W. ton and at that rate	Years. 20	Per Cent. 5
Barges, harbor tugs, or other small floating equipment	5	20
Filling stations:		
(1) Ordinary wood or corrugated construction	5	20
(2) Brick and concrete, or extraordinary construction	10	10
Distributing stations	10	10
Tank wagons:		
Motor type	4	25
Horse type	6	16⅔
Steel barrels	7	14⅔
Tracks and switches	8	12½

In considering depreciation on filling stations the factor to be given and most consideration is location. The normal life of equipment and buildings is at least 10 years, but unless the station is favorably situated it may only last 2 or 3 years.

NOTE.—Filling stations are divided into two classes: (*a*)

Stations that have temporary wooden or corrugated iron buildings; and (*b*) stations that have buildings of brick or terra cotta, where the investment in buildings represents a large percentage of the total investment.

Distributing stations with exception of delivery equipment do not depend to such a large extent on location, and for that reason are given a longer life, although if delivery equipment is taken into consideration the depreciation rate for the whole plant would no doubt be higher than for filling stations. Delivery equipment, such as tank wagons, horses, trucks, etc., constitute a large percentage of the investment in distributing stations and are short lived; therefore, in calculating depreciation on distributing stations the relative investment in warehouse equipment and in delivery equipment must be taken into consideration.

The rate of depreciation on tank cars is the same as that given under refinery equipment. The investment in tank cars is really a special item when considering sales equipment as a large number of marketers do not own any tank cars at all.

The same thing applies to marine equipment, since only the large companies that do an extensive export business possess marine equipment. It is believed that an average depreciation rate of 10 per cent or a life of 10 years will cover this class of equipment since equipment such as bulkheads, docks, etc., have a life of only 4 to 6 years, while floating equipment, such as tankers, will easily last 20 years.

CLASS E.—NATURAL GAS—UTILITY COMPANIES.

The drilling equipment and well equipment of natural gas companies should be depreciated at the same rate as drilling equipment and well equipment for oil wells, previously given.

The following depreciation rate is suggested for gas-pipe lines:

	Per Cent.
Mains	$8\frac{1}{3}$
Gathering lines	10
City lines	10
Compressor stations, including gas compressors, engines, boilers and equipment, should be grouped into one heading and depreciated at an annual rate of	$14\frac{2}{7}$
Gathering stations	$16\frac{2}{3}$
Field stations	25
Meters and regulators	20

The information at hand in which the cost of the equipment was taken into account showed that a natural gas plant could be depreciated, as a whole, at a rate of 10 per cent. It is a general consensus of opinion that the average life would not be over 10 years.

It is recommended that conditions existing on January 1, 1916, be used as a basis, and that all expenses incurred to maintain the output or carrying capacity of lines, as of that date, be treated as follows:

That intangible expenses may be charged direct to maintenance as an operating expense.

That tangible items be charged to investment or capital account and should be given a 25 per cent salvage value and the remaining 75 per cent charged off at the rate of $17\frac{1}{2}$ per cent per annum for all gas properties other than those in West Virginia, Pennsylvania, and possibly Ohio, where the natural gas plants, as a whole, should be given a 15-year life, and the extensions figured on a 7-year life on a 15 per cent salvage, and the remainder charged off at the rate of 12 per cent per annum.

The above conclusions are based upon a 7-year life for gas fields in West Virginia, Pennsylvania, and possibly certain portions of Ohio, and on a 4-year life for all other gas fields.

The shorter life for the other gas fields can be substantiated by numerous examples, such as Southern Kansas, Hogshooter, Cushing, and Pawhuska fields, all of which were large producers and were all practically exhausted within less than five years, in which the bulk was taken out within the first three years.

CLASS F.—NATURAL GAS GASOLINE PLANTS.

Compression plants may be divided into compressors, engines, boilers, auxiliary equipment, cooling equipment, gathering and distributing lines, blending tanks, buildings, and electrical equipment.

For absorption plants, separate items of absorbers, stills, condensors, cooling equipment, auxiliary equipment, boilers, engines, electrical equipment, tanks, and loading racks may be considered.

On the whole the average life of these plants is not over five or six years.

The Fuel Administration made a survey of cost of natural gas gasoline plants. Over 800 questionnaires were sent out and of these about 400 were considered. Out of 175 plants tabulated nearly all are new plants or less than two years old, and of those operating at a loss almost all were over four years old. The returns of some 200 other plants were considered and are older plants, and were either not operating or were so defective in their detail as not to be usable for comparative purposes.

In consideration of these data and other data at hand, it is recommended that:

The original cost be placed on a 20 per cent salvage, and the remaining 80 per cent be depreciated in four years at 35, 20, 15, and 10 per cent in the respective years.

SUMMARY.

Class.	No.	Reference.		Useful Life.	Annual Depreciation.
		Page.		Years.	Per Cent.
A	1	68	Drilling equipment	4	40–25–15–10
	2	68	Wells	.....	.....
	3	69	Dehydrators:		
			Electric	5	20
			Pipe and tanks	2	50
	4	69	Tanks:		
			Steel 5,000–55,000 bbls	20	5
			2,500–5,000	12	8⅓
			Galvanized iron 500–2,500	12	8⅓
			Less than 500	8	12½
			Wood	5	20
			For movable tanks:		
			Galvanized iron 500–2,500	9	11⅓
			Less than 500	6	16⅔
			For water tanks:		
			500–2,500	8	12½
			Less than 500	5	20
	5	70	Tools	3	33⅓
	6	70	Transportation equipment	3	33⅓
	7	70	Water plants	10	10
	8	70	Electric equipment	10	10
	9	71	Machine shops	7	14⅔
	10	71	Buildings:		
			Small wood	10	10
			Frame structure	15	6⅔
			Corrugated iron siding	6	16⅔
			Concrete	25	4
			Brick	25	4
			Steel	25	4

Summary—Continued.

Class.	No.	Reference.		Useful Life.	Annual Depreciation.
		Page.		Years.	Per Cent.
B	1	71	Pipe lines:		
			Mains over 6 inches diameter	20	4½
			Mains under 6 inches diameter	16	5¾
			Gathering lines	10	9
			Less 10 per cent salvage.		
			Pump stations	10	10
C	....	72	Tank cars	20	5
	1	73	Refineries:		
			Class 1.—Located at point assuring a long supply of crude oil; or well-constructed plants	20	5
			Class 2.—Located at points assuring supply of crude oil for several years	10	10
			Class 3.—Skimming plants and small refineries of poor construction, or located at points where supply of crude oil is not assured for a long period of time	6	16⅔
D	1	75	Sales or marketing equipment:		
			Tankers	20	5
			Barges	5	20
			Filling stations—		
			Class A.—Ordinary wood or corrugated steel construction	5	20
			Class B.—Brick and concrete or extraordinary construction	10	10
			Distributing stations	10	10
			Tank wagons—		
			Motor	4	25
			Horse	6	16⅔
			Steel barrels	7	14⅔
			Track and switches	8	12½
E	....	76	Natural gas (utility companies):		
	1		Drilling equipment. (See A-1.)		
	2		Wells. (See A-2.)		
	3		Gas pipe lines—		
			Mains	12	8⅓
			Gathering lines	10	10
			City lines	10	10
	4		Compressor stations	7	14⅔
	5		Gathering stations	6	16⅔
	6		Field stations	4	25
	7		Meters and regulators	5	20
			Considered as a whole plant	10	20
F	1	77	Natural gas gasoline:		
			Plant—Compression, with 20 per cent salvage value	4	35–20–15–10
			Absorption plants, with 20 per cent salvage	4	35–20–15–10

PART III.

ESTIMATION OF RECOVERABLE UNDERGROUND RESERVES OF OIL.

PREFACE.

There has been a sincere effort on the part of many petroleum engineers and technologists during the past few years to devise a rational system for estimating underground reserves of oil. Much valuable work along this line has been done by various engineers and results have been given out from time to time in the publications of the technical societies and Government bureaus.

All sorts of methods and systems have been devised and most of them have merit, but the great difficulty has been to find one capable of general application.

Since the enactment of the income and war revenue tax laws producers have become much interested in this work, as they, as well as the technologists engaged in it, realize that the only channel through which might come equalization of the tax burden on them is in the proper valuation (when permissible) of oil properties, careful estimates of the underground reserves, and then the use of these two factors in the computation of proper depletion allowances.

During the autumn of the year 1918, the Internal Revenue Bureau of the Treasury Department, with the active cooperation of operators in the various districts, undertook the collection and tabulation of production data from all the fields in the United States for the purpose of making an intensive study of depletion. Records of production of thousands of properties were collected and tabulated. These were carefully gone over and studied by the most competent and experienced men in the country and the average future production curves and tables reproduced on succeeding pages of this manual are the result of their work.

This study has confirmed the belief heretofore held that it is possible to make estimates of recoverable underground reserves of

oil within reasonably narrow limits. It has shown that in the making of such estimates it is simplest and safest to use some variation of production curve methods, because by the use of the productive history of a well or property as a basis for a prediction of its future, estimation is confined to the future and the personal equation thus reduced to a minimum.

Production curves and the methods for using them in making estimates of underground reserves are very fully described in section A following. It may not be out of place here, however, to state briefly that a production curve is a graphic representation of the decline in production of a well or group of wells, and that the problem presented to the estimator is the extrapolation or extension of the curve from the period of last recorded production to the economic limit for the property.

A method devised for use in the older fields uses an average decline curve for this purpose, because a careful comparison of production records shows that while the rate of decline in production varies widely over the country as a whole, when the production records from smaller units such as pools are tabulated, the decline rates of individual wells or properties show a striking similarity, although there may be wide variations in gross production figures. In view of this fact, the data collected are grouped according to pools, and a curve plotted to show the average decline in production per well for the pool. This curve, or such portion of it as is necessary, is reproduced in the extrapolation of the decline curve for any particular property within the district, but it must be used with caution because this average decline curve is only an average, and the probabilities are that each group of wells within the district is either above or below the average. However, with care and the use of judgment, the decline curves of any particular property may be extended in this manner and the results made to show very conservatively and within reasonable limits just what the property may be expected to produce in the future.

To make the average decline curve the graphs from the production records for all the tracts in the district are assembled and assorted according to the amount of production in the last year shown and arranged in ascending order. The average interval of time required for the decline between certain arbitrarily fixed points, such as from 100 barrels to 50 barrels, or 1,000 barrels to 500 barrels, is found by ascertaining the numerical average of the

time interval required for such decline on each of the properties in the district. The average declines so obtained are plotted and the resultant curve represents a true numerical average decline for every well in the district.

This curve is simply an average of averages in decline and deals with known factors only.

Its greatest fault seems to lie in the fact that in the computation of averages, only the records of those wells which are exhausted, or very nearly so, can be used in the construction of the lower end of the curve, and usually the best wells are at the same time producing at a rate which may be considerably above the economic limit of the field. Consequently, the tendency of the lower end of the curve is to show that the underground reserves are somewhat less than they will actually prove to be.

The advantage in the use of this method lies in the fact that all production records, no matter how erratic they may be, are used in its construction, without any smoothing out processes. A further advantage is that the personal equation as a factor in its construction is entirely eliminated.

This is only one of many methods devised for making an average decline curve, and in turn the average decline curve is only one way of estimating reserves by production curve methods.

For the convenience of those not accustomed to reading values from curves, tables have been prepared showing the average future production which may be expected from a well in most of the districts in the country if the production for the taxable year is known. Curves and tables are the same thing in different form.

One thing, however, must be borne in mind. These curves and tables represent *average* conditions only in the field or pool to which they apply. Everyone knows that an average well or property is seldom encountered, so in the application of curves or tables to a specific property due allowance must be made.

A striking feature observed in connection with the study of these curves is that many decline curves of individual wells or properties which are anywhere near symmetrical, seem to assume approximately the shape of an hyperbola. Much interesting work has been done in the investigation of this feature with a view to the extrapolation of decline curves mathematically, because if a true decline curve is hyperbolic in form, when plotted on logarithmic coordinate paper it becomes a straight line, with the unknown

factor in its equation, which is the slope of the line, definitely fixed in the earlier periods of production. This method of extrapolation of decline curves is worthy of consideration, but until better understood it must be used with extreme caution.

As an essential element in calculating depletion allowances in the estimation of underground reserves, the rather full discussion of the methods found best for making these estimates by investigators working with the department is given in this manual, for no single method or formula which may be generally applied has been found.

The statement has been made many times in these pages, and can not be too strongly emphasized, that the curves and tables presented herewith represent only average conditions.

In many cases they may be used safely by the operator of a single property. Where, however, holdings in any field or district are in any way extensive, it will, in most cases, be necessary for the operator to make special estimates, using any or all of the methods discussed in this manual, or it may even be found necessary to devise new combinations to fit the peculiarities of a particular tract.

In any event, care, skill, and judgment must be exercised to the utmost, and it is believed that the effort expended in this work on the part of the oil producer will be repaid many fold. Not only from a tax standpoint will this benefit come. A full knowledge of conditions such as will be brought out by a study of this problem will put the oil-producing business generally on the much firmer and safer foundation to which it is rightfully entitled.

Section A.

METHODS OF ESTIMATING RECOVERABLE OIL RESERVES.

Estimation of recoverable oil is possible.—The estimation of the future production of oil wells or of the recoverable oil underlying a property in the past has been considered an almost unsolvable problem, but scientific progress has disclosed reasonably accurate solutions, especially where sufficient dependable data are brought together and arranged in an orderly manner, for then it becomes evident that there is " a system to things " and that " freaks " are comparatively few. The recovery of oil is controlled by scientific

laws, and where enough facts are known these laws make themselves manifest.

During the past ten years many petroleum engineers have been working on the problem of estimating the future production of oil wells, and much progress has been made. In fact, when enough facts are available, surprisingly close estimates are usually possible, and in the future, as more and more data are compiled and analyzed, it will be possible to make much closer estimates.

Plotting production curves.—The production-curve method is one of the simplest and, when sufficient data are available, is, perhaps, the most accurate of all the methods for estimating the future production of oil wells. A production curve is a graphical record of the production of a well or group of wells, plotted on coordinate paper (Fig. 1). It is desirable to have the production records of individual wells, but as these are kept in but a few fields, it is usually necessary to use the production record of the group of wells on a property.

To provide a basis of comparison between wells, the yearly production of a property is divided by the number of wells producing each year, thus giving the average production per well for each year. The record of an Oklahoma property that has been prepared for plotting in a production curve is given herewith.

Year.	Production.	Wells Producing.	Average per Well.	Year.	Production.	Wells Producing.	Average per Well.
	Barrels.		Barrels.		Barrels.		Barrels.
1906	46,860	5	9,372	1912	2,462	6	410
1907	31,717	6	5,286	1913	1,641	6	274
1908	15,003	6	2,501	1914	1,061	6	177
1909	11,031	6	1,838	1915	578	6	96
1910	7,047	6	1,174	1916	218	6	36
1911	4,522	6	754				

On a sheet of coordinate paper, as in Fig. 1, the spaces between the light horizontal lines represent 100 barrels each and those between the heavy lines which are ten times as far apart, represent 1,000 barrels each. The heavy vertical lines represent years; thus, space between the horizontal lines represents production and between the vertical lines time. For convenience, these lines are labeled on the margins as in Figs. 1 and 2.

Taking the record given, the first year is 1906, during which

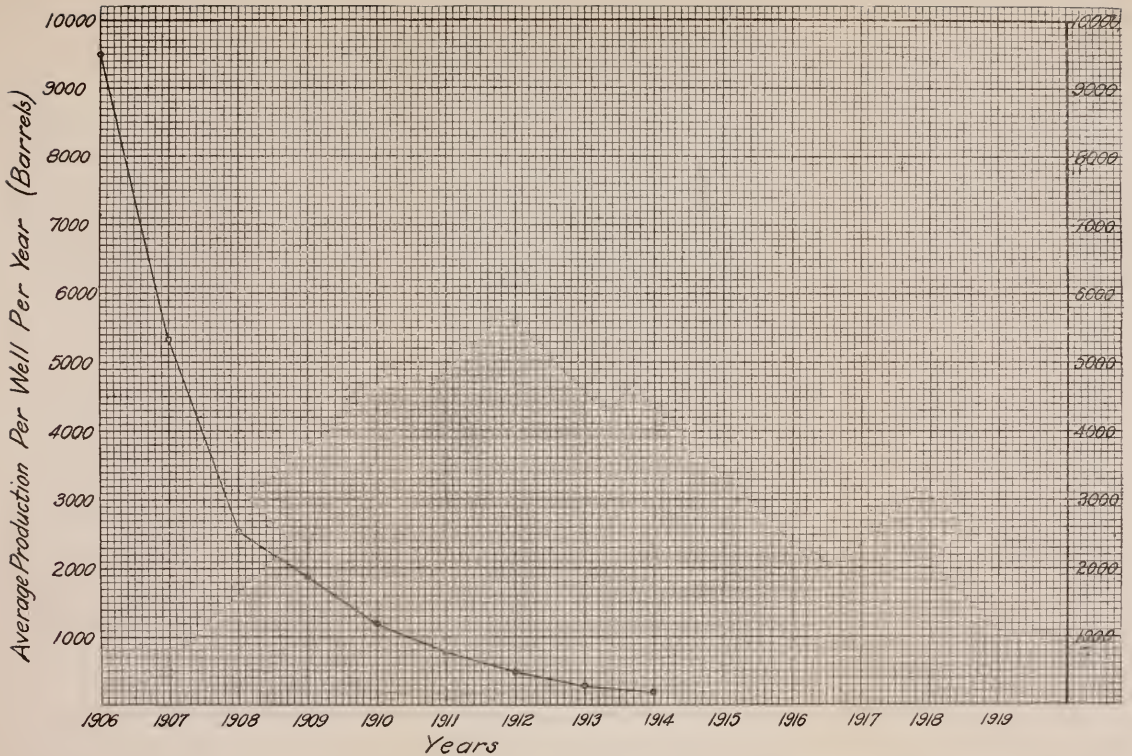

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FIG. 1.—PRODUCTION DECLINE CURVE FOR A PROPERTY IN OKLAHOMA.

(To face page 84.)

15
LINE

15
LINE

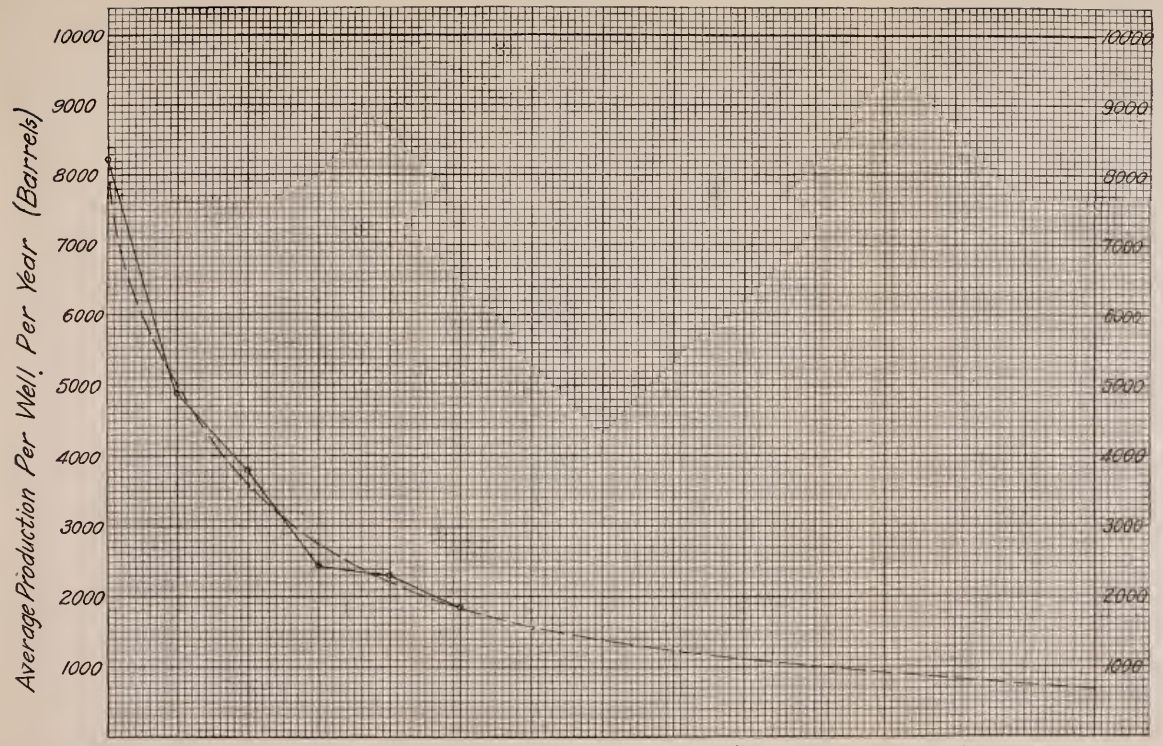

FIG. 2.—PRODUCTION DECLINE CURVE, SHOWING THE EXTENDED CURVE OF PROBABLE FUTURE PRODUCTION.

111069°—19.

(To face page 85.)

year the average production for each well was 9,372 barrels. A point is then made on the vertical line representing the year 1906 and a distance representing 9,372 barrels above the bottom, which is 9 heavy lines and $3\frac{3}{4}$ light lines. Similarly a point is made on the line representing 1907, 5 heavy lines and 3 light lines above the bottom. And on the line representing 1908, 2 heavy and 5 light lines above the bottom show the production of 2,501 barrels for that year. The production for the rest of the years are then plotted and the points connected up by lines to make the curve as in Fig. 1. It will be observed at once that the plotted record makes a fairly regular and symmetrical curve.

Manifestly, there is a certain relation between the production of the successive years that is not easily seen in the column of figures from which this curve was derived. Plotting production records in this manner has many advantages and permits the mind to grasp readily facts that otherwise would be obscured in a mass of figures.

Estimating future production by production curves.—Many thousand production or decline curves have been plotted by petroleum engineers in the manner shown, and from this wide experience it has developed that the relationships between the production of various years are such that the curves are usually notably symmetrical. Furthermore, it has been found that such curves can be extended beyond the actual period of production by continuing the curves in accordance with their symmetry and that such projections, if skillfully made, provide fairly trustworthy estimates of the future production of the well.

The estimation of the future production by the curves of past production is illustrated in Fig. 2. The actual record extends six years—from 1911 to 1916—and is shown by the small circles connected by the heavy lines. The dotted line shows the symmetry of this portion of the curve and beyond the year 1916, shows the extension from which estimates of future productions are made up to the year 1925. For 1917 the estimated production is 1,700 barrels, for 1918, 1,500 barrels, and for 1919, 1,300 barrels. By adding these estimates of the future years, an estimate of the total future production is obtained.

It is to be noted that production curves like Figs. 1 and 2 deal with actual facts and conditions on particular properties. Only the oil gauged is considered, hence all the various practical facts

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It is to be noted that production curves like Figs. 1 and 2 deal with actual facts and conditions on particular properties. Only the oil gauged is considered, hence all the various practical facts

of field conditions are automatically taken into account. The extension of the curve estimating future production is based on the past behavior of the wells on the particular property which established the symmetry of the curve. This symmetry is not accidental but is the result of underlying natural laws governing the expulsion of the oil from the producing strata. In Fig. 1 it is evident that the production of the last six years could have been closely estimated from the production curve of the first five years. This method and others based on it have proved satisfactory in the appraisal of many large properties.

Obviously, manner of operation, accidents, and other factors will influence the future production just as they have the past production, but experience has shown that ordinarily these are not likely to cause wide deviation from estimates that have been carefully made. Examination of the individual production records will show whether the probability of such occurrences will make estimates unsafe.

The Appraisal-curve method.—The production-curve method, just discussed, necessitates a record of at least four years before any reliable estimate of the future production is possible, and usually such estimates can not be made satisfactorily until the wells have produced for several years. In the most satisfactory methods for properties that have not produced this long, the future production of wells is estimated by comparison with the behavior of other wells in the same or similar districts that have produced long enough to establish trustworthy production curves. Usually the methods of estimation are based on the average behavior of the older wells because the behavior of the new wells will approximate this average.

The appraisal curve is built up from records of individual wells or groups of wells within a certain district and is applied to wells within the same district that have not produced long enough to permit estimates of future production by extension of the production curve. It may be necessary at times to apply appraisal curves of one district to other districts for which there are not enough reliable records to make appraisal curves, and in such cases care must be taken to select curves from districts most similar.

The appraisal curve, illustrated by Fig. 3, is based on the relation that exists between the production of wells for their first year, and the quantities of oil they will produce ultimately. This

particular figure was drawn from the production records of 209 properties in an Oklahoma field. As the average property in that field contains 10 producing wells, the figure may be said to represent about 2,000 wells. The records of each property were taken and each year's average daily production per well was computed and curves plotted from them. Only records where practically the full production had been obtained or where the future could be estimated with confidence were used. From these curves the future production of each property was estimated as explained above (Figs. 1 and 2). The future production of each property was added to past production to determine the ultimate production for each property. The next step was to plot for each property the average production per well during the first year or second year against the ultimate production of the well. Each dot, therefore, on Fig. 3, shows the average production per well the first year on a property and the estimated average ultimate production per well.

These dots, which represent the ultimate production of more than 200 properties, on which the wells were of many different sizes the first year, arrange themselves in a strikingly orderly manner, leaving no doubt of the existence of a definite relation between the first year's production of a well and its ultimate production. There is a considerable variation in ultimate production, however, both for wells of different and for wells of the same initial output.

These dots define the positions of the three curves drawn in to show the average and the range in ultimate production that may be expected from wells of different output in this field. It shows that two wells in this field with the same production the first year may produce different totals, yet the amount that a well of a certain output will produce will not exceed a certain maximum, nor will it be less than a certain minimum. The producer, therefore, can be reasonably sure that he will not get more than a certain maximum amount of oil nor less than a certain minimum amount and is really more likely to obtain finally the amount shown by the average curve than either the maximum or minimum.

Fig. 3 has been worked out on the law of averages similar to the fundamental laws underlying life insurance. Actuaries know, not by theory but from the analysis of great masses of data, the probable life of a man of any specified age, though an individual man might die the next day, or, on the other hand, might live to be

of a very old age. If 10,000 men are considered, however, it is possible to predict within extremely narrow limits the age at which the average man of the group will die, and also how many men of the 10,000 will die at any specified age.

The method illustrated in Fig. 3 makes use of the first year's production, but the most recent year's production may be used with equal assurance, and the total production, beginning with the production of the well for the past year, can be worked out in the same manner. This fact is based on a conclusion for which there seems to be abundant statistical proof. This is as follows:

If two wells under similar conditions produce equal amounts during any given year the amounts they will produce thereafter, on the average, will be approximately equal, regardless of their relative ages. That is, if two groups of wells in the same pool have averaged, say, 5 barrels per day during the past year, they will on the average produce the same amount of oil in the future, even though the wells of one group may be only 2 years old, whereas the wells of the other group may be 5 years old. The writers were at first skeptical, but finally were forced to this conclusion because of the preponderance of evidence disclosed by the records of many thousands of wells in many different fields.

It must be carefully noted that the above statement is made for the *average* and applies to only one pool. The future production of any two wells may differ widely but for two large groups of wells in the same district whose current production averages the same, the statement holds true, hence if nothing is known of the past histories of two wells from which their futures may be estimated, their chances of production will be equal even though one well is much older and according to the popular idea has a more settled production.

This law of equal expectations makes possible the derivation of appraisal curves like Fig. 3 by other methods than the one illustrated. The curves for many of the fields were checked by two or more methods of derivation.

To estimate future production from this curve it is necessary to know the first or the most recent year's production and the number of wells producing during that year. From this the average production per well is computed. Readings are then made at the intersections of the vertical lines, representing the average yearly production per well with the curves, and the horizontal lines

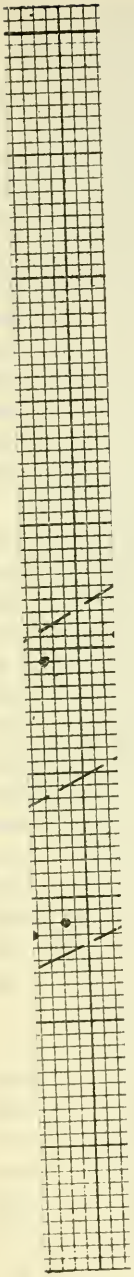

FIG. 3.—A

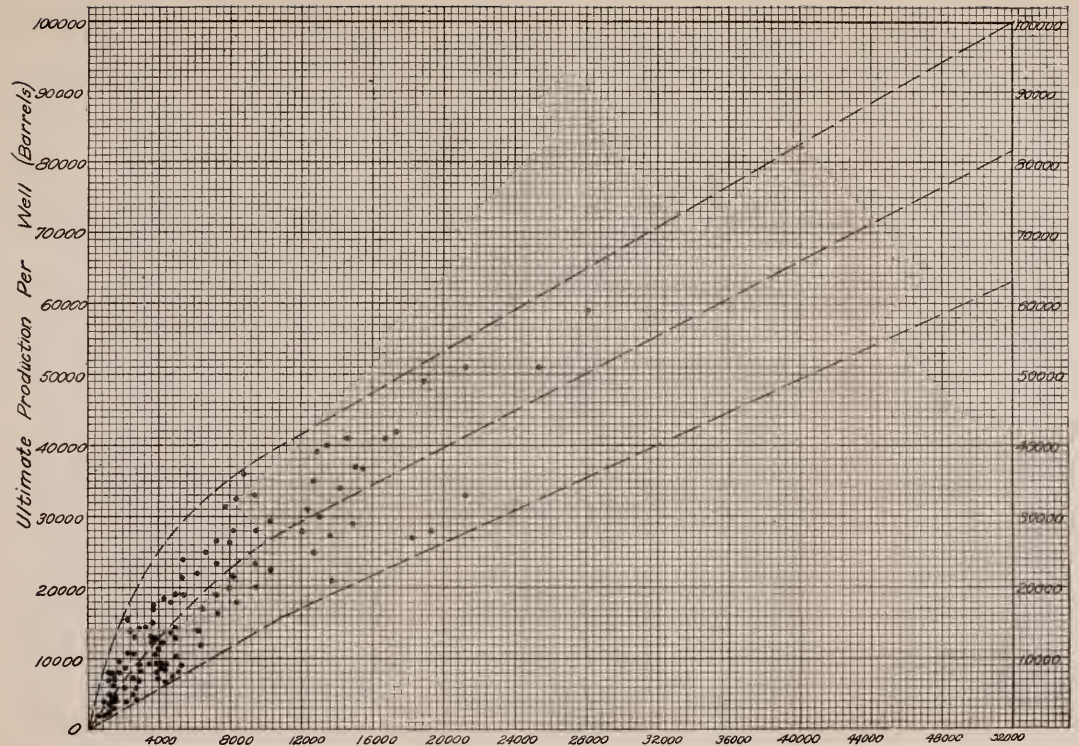

FIG. 3.—APPRAISAL CURVE FOR AN OKLAHOMA OIL FIELD.

(To face page 88.)

on which these intersections lie are then followed to the right or left. This gives the maximum, average, and minimum ultimate production that may be expected per well. For example, if the wells average 30 barrels daily during any year, the 30-barrel line is followed vertically to the intersection with the minimum curve at 16,200, the average at 28,000, and the maximum at 40,500 barrels. Thus, the average 30-barrel well will produce not more than 40,500 barrels, at least 16,200 barrels, but more likely it will produce approximately 28,000 barrels. To compute the future production, the year's production—10,950 barrels—must be subtracted from these estimates. This gives the maximum, average, and minimum future estimates as 29,550, 17,050, and 5,250 barrels, respectively.

In some cases the average future production curves shown in the succeeding pages were determined in this way—that is, the past year's production was subtracted from the estimated average ultimate production, as shown by the average ultimate production curves. These estimates of average future production were plotted and a curve drawn through the plotted points. In other cases the future-production curves were derived directly from the average-production curve. By multiplying these estimates of future production by the number of producing wells, the estimated future recovery for the developed portion of the property may be ascertained. It should be remembered, in using these future-production curves, that they represent the *average* and were based on all the evidence available. They do not take into consideration the increase in oil production due to the use of stimulative processes, such as compressed air, reshooting, flooding, etc.

In the appraisal curve (Fig. 3) it is to be noted that though the limits of variation are set for a well of a particular size, these limits permit a considerable variation. If nothing is known beyond the first year's production, it will be necessary to assume that the well is an average well and the average curve should be used. The probabilities are that the well will actually be nearer the average than either extreme, as shown by the dots on Fig. 3. If, however, the record extends back two or more years it becomes possible to tell whether the well is an average well or if it deviates from the average the direction and degree of such deviation. In other words, the longer the past history of the well, the more nearly

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it can be classified according to its probable future behavior. If the record is long enough, a production curve like that shown in Fig. 2 may be used which will in such case be preferable to these general curves. In estimating the future production, the estimates should be revised at the end of each year instead of carrying forward errors from year to year. In this way poor estimates caused by lack of data or changed conditions on the property are not perpetuated. To show how these readjustments are made, the following example is given:

A property gave an average production of 12,410 barrels, or 34 barrels per well per day, during the first year. An average 34-barrel well in this field would produce a total of 30,500 barrels ultimately, of which 12,410 barrels (34×365) were produced during the first year. This leaves a future production of 18,090 barrels per well. In order to determine the average daily production for such a well during the second year, we must assume the figure of 18,000 barrels as its ultimate production. Applying the aforesaid curve (Fig. 3), we follow the horizontal line representing this ultimate production across the chart to its intersection with the "average" curve. This gives 5,840 barrels, or 16 barrels as the first year's average daily production as a well with this ultimate production. Applying the law stated on page 88, it becomes evident that the above figure of 16 barrels is approximately equal to the daily production for its second year of a well which produced 34 barrels daily during its first year. Multiplying 16 by 365 gives a total of about 5,840 barrels, which represents the amount produced during the second year. The sum of the first and second year's production of this well is about 18,070. This amount deducted from the original ultimate production of 30,500 barrels leaves a future production of about 12,430 barrels. By repeating the same process for each successive future year until the estimated ultimate production is extinguished, the total decline of this well will be obtained.

Suppose the well actually produced 20 barrels per day, however, instead of 16 barrels, or 7,300 barrels for the year instead of 5,640. This means that the well is above the average by 30 per cent, and proper corrections are therefore made. By this means estimates may be corrected yearly and the depletion charges made more and more accurate as time goes on.

Unusual cases will have to be dealt with separately. For

instance, it may not be possible to make trustworthy estimates of the future production of some wells by this method, because of the irregularity of their production. Also, those wells wherein stimulative processes are used will have to be considered separately. Wherever the wells on a property produce regularly, however, and where the property is fairly well drilled up, and the proved acreage can be easily determined, the above method should be of great value to the oil producers in making estimates of future production

The same general procedure may be applied in making estimates of the ultimate production of undrilled but proven oil land. *Proven oil land is that which has been shown by finished wells, supplemented by geologic data, to be such that other wells drilled thereon are practically certain to be commercial producers.* The average future production curve may be used in making estimates of the future production of a practically drilled up near-by similar tract and the ultimate production per acre estimated. These values, with necessary modifications, on account of position on structure, sand characteristics, drainage, etc., may be applied to the undrilled tract

Another method is to estimate the first year's production of wells to be drilled on the proved land and determine their future by use of the average future production curve. The ultimate production of the tract is the sum of the future production and of the first year's production.

Any estimates of the amount of oil that will be recovered from an undrilled but proven tract are subject to great inaccuracies. They are estimates in the truest sense of the word, but it is believed that this method is as satisfactory as any other for obtaining the probable productivity of a tract.

No attempt has been made to cover all the ramifications of the problems of estimating the future production of wells or of the underground reserves of undrilled area. The purpose of this article has been, first, to point out that if sufficient data are collected and analyzed, the law of averages discloses systematic relations between the past and future production, and, second, to show one convenient method that may be used to estimate reserves as a basis for calculating depletion deductions in a sicentific manner.

SECTION B.

AVERAGE FUTURE PRODUCTION CURVES AND TABLES.

FUTURE PRODUCTION CURVES FOR THE APPALACHIAN DISTRICT.

The Appalachian oil and gas district occupies an elongated elliptical-shaped area extending northeast and southwest across the Appalachian Plateaus from southwestern New York to Tennessee, a distance of about 500 miles. In its broadest part, centering in eastern Ohio, the district is about 150 miles wide. Thence northward and southward the productive zone rapidly diminishes in width, and its extension across Kentucky is by small, widely separated pools. The area of greatest oil development occupies a narrower zone which averages less than 50 miles in width and centers in the panhandle of West Virginia.

The oil and gas bearing sands occur throughout a long stratigraphic interval, including rocks ranging in age from Ordovician to Carboniferous. The strata consist of preponderating shale, lenses of sandstone—which are the main oil and gas horizons—and subordinate limestone. The sandstones merge into shales toward the west, where there is also a greater proportion of limestone in the section. There is a marked decrease in thickness of the strata toward the west, notably of the Upper Devonian. This is shown by the increase in the interval between the Berea sandstone and the Corniferous limestone, from 500 feet in central Ohio to more than 5,800 feet in northern West Virginia. And southward across West Virginia there is a notable thickening of the Pottsville formation. For this reason and because of the basin structure of the district the " Clinton " sandstone which occurs between two and three thousand feet beneath the surface in central Ohio is more than 7,000 feet deep in western Pennsylvania and northern West Virginia where it was not encountered in two recently sunk very deep test holes.

The Appalachian oil and gas district lies in the geosyncline that extends between the Cincinnati anticline on the west and the zone of steeply folded rocks of the Allegheny Mountains on the east. The syncline is a spoonshaped trough in which the rocks rise northwestward, northward, and southeastward from the lowest part of

the basin situated in West Virginia near the southwestern corner of Pennsylvania. Superimposed on this larger structure are a series of folds by which the rocks are warped into irregular and generally nonpersistent anticlines and synclines, the axes of which undulate and overlap. The axial trend throughout the greater part of the district is northeast-southwest, but in southern West Virginia and Kentucky the trend becomes more westward. The folds decrease in intensity westward from the eastern margin of the district and west of the axis of the geosyncline the folding is so gentle that the rocks are warped into irregular wrinkles without marked axial trend. Along the western margin of the district the folds practically disappear and give way to a monocline on which the rocks rise westward at the rate of about 60 feet per mile.

Considered as a whole, the most productive oil belt occurs contiguous to the central axis of the geosyncline and the largest accumulations of gas are found along the outer margins of the trough. But pools of oil and gas of varying size separated by nonproductive areas are irregularly distributed throughout the district. The pools are characteristically elongated in outline and their longer dimensions are prevailingly parallel to the structural trend. The location of most of the gas pools has been distinctly determined by structure. They occur along the crests of anticlines or along the updip termination of lenses of sandstone where they merge with shale, or where there is a marked decrease in porosity of the pay sand. The influence of structure on oil accumulation is also pronounced. In the absence of gas some oil pools occur on the crests of anticlines. Where much gas is present pools occur on the flanks of anticlines below the gas and above the edge water; others occur on terraces marked by changes in the rate of dip. In the absence of water in the rocks, petroleum tends to occur in the synclines. But in many pools the effect of structure is not so evident and lithology has been the controlling factor. The location of many of the oil pools in the Appalachian region is principally due to the position and porosity of the lenticular reservoir rocks. These factors account for the irregular shape of many of the pools and for their not uncommon occurrence " off structure."

The petroleum from the Appalachian region is a high-grade paraffin oil. The product of New York, Ohio, Pennsylvania, and West Virginia has an average specific gravity not far from 0.800 (45° Baumé). The average for Kentucky is not quite so high.

The total production of petroleum in New York, Pennsylvania, West Virginia, Kentucky, and Tennessee down to January 1, 1917, was 1,060,338,464 barrels. Complete data for the Appalachian region as a whole are not available because separate figures have not been kept for eastern Ohio district from the western part of the State, which is included in the Lima-Indiana district.

The maximum annual output for New York and Pennsylvania was obtained in 1891, when more than 33,000,000 barrels were produced. Since 1900 there has been a fairly uniform decrease in production down to 1912, when the lowest annual production, 8,712,076 barrels, was recorded for New York and Pennsylvania. In 1913 and 1914 there were slight increases and for the last five years the variation in production from year to year has been abnormally small. This change in rate makes the extension of the curve, in an endeavor to estimate future yield, somewhat doubtful. Nevertheless, because the peak production was attained so many years ago the extrapolated curve affords a good index of what may be expected in the future. The improbability of considerably extending the producing area is generally admitted and it does not seem likely that future discoveries will increase the present rate of production to any considerable extent.

Extension of the production curve indicates that approximately 85 per cent of the recoverable oil from New York and Pennsylvania has been exhausted under present operating conditions.

Wells in the Appalachian region are sunk by the standard or churn system of drilling. The rocks are hard and comparatively little casing is required as contrasted with drilling in the loosely consolidated rocks of other districts. The wells range in depth from a few hundred feet in parts of eastern Ohio and Kentucky to between 3,000 and 4,000 feet to reach the deeper sands in southern Pennsylvania and West Virginia.

Bradford Sand, Cattaraugus and Allegany Counties, N. Y., and M'Kean County, Pa.

The Bradford sand is one of the longest lived producers of the Appalachian district. It is of Upper Devonian age and is encountered at depths ranging from 1,300 to 1,700 feet. The pay is unusually thick, averaging about 35 feet, and is commonly fine

grained and homogeneous. Porosity averages 18 per cent by volume. The curve is based on the records of tracts in most of which continuous production data go back to the opening of the field. A fair average of production for the entire field is a quarter of a barre' per well per day and many wells yield only one-tenth of a barrel per day. The curve shows estimated average future production without reference to flooding. The recent introduction of the so-called " water drive " or flooding method of rejuvenating old properties is accomplishing some remarkable results, but records do not go back far enough to warrant prediction as to ultimate production.

ESTIMATED FUTURE PRODUCTION TABLE—BRADFORD SAND

Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
30	0	300	2,450	800	4,700
50	250	400	2,950	900	5,050
100	850	500	3,400	1,000	5,400
150	1,400	600	3,850	1,250	6,100
200	1,800	700	4,300	1,500	6,600
250	2,150				

Speechly Sand Pool, Concord Township, Butler County, Pa.

The Speechly sand pool in Concord Township, Butler County, Pa., was opened up in 1902, as the result of deepening a well in an

ESTIMATED FUTURE PRODUCTION TABLE—SPEECHLY SAND.

Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
50	0	300	1,800	800	4,350
100	350	400	2,550	900	4,650
150	700	500	3,150	1,000	4,950
200	1,100	600	3,600	1,250	5,550
250	1,450	700	4,000	1,500	6,100

old Fourth Sand pool. The wells range between 2,200 and 2,400 feet in depth and the spacing is approximately 7 acres per well. The sand is of Upper Devonian age and varies from 15 to 22 feet in thickness. The oil has a specific gravity of about 0.800 (45° B.)

Hundred Foot Sand, Butler and Allegheny Counties, Pa.

The Hundred Foot is one of the principal sands in Butler and Allegheny Counties, Pa. The sand is persistent over large areas and ranges between 50 and 125 feet in thickness. It is usually medium grained, but is irregularly streaked with lenses of conglomerate, which commonly are the pay streaks of which there may be several. Production from the Hundred Foot sand is characterized by the occurrence of considerable water which is pumped with the oil. It is of Upper Devonian age and is found at a depth of about 1,400 feet. The oil has a specific gravity of about 0.800 (45° B.)

ESTIMATED FUTURE PRODUCTION TABLE—HUNDRED FOOT SAND.

Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.
Barrels.	Barrels	Barrels.	Barrels.	Barrels.	Barrels.
50	0	300	1,300	800	3,000
100	300	400	1,700	900	3,250
150	600	500	2,050	1,000	3,600
200	850	600	2,350	1,250	4,550
250	1,050	700	2,700	1,500	5,650

Dorseyville Thirty-foot Pool, Allegheny County, Pa.

This pool was opened up in 1913 and caused some excitement because of its occurrence in the midst of old development. Some of the wells had an initial monthly production of more than 7,000 barrels. The pay sand—the Thirty Foot of Upper Devonian age—is coarse grained and averages only about 8 feet in thickness. Production accordingly has fallen off rapidly. The wells range between 1,700 and 2,000 feet in depth. Wells are irregularly spaced and development has been characterized by a number of dry holes. The oil has a specific gravity of about 0 800 (45° B.).

ESTIMATED FUTURE PRODUCTION TABLE—DORSEYVILLE POOL.

Average Production per Well During Year.	Estimated Average Future Production per Well.	Average Production per Well During Year.	Estimated Average Future Production per Well.	Average Production per Well During Year.	Estimated Average Future Production per Well.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
50	0	800	800	2,750	1,900
100	100	900	900	3,000	2,050
150	150	1,000	950	3,500	2,300
200	200	1,250	1,100	4,000	2,500
250	300	1,500	1,250	4,500	2,700
300	350	1,750	1,400	5,000	2,900
400	450	2,000	1,550	6,000	3,300
500	550	2,250	1,650	7,000	3,600
600	650	2,500	1,800	8,000	3,950
700	750				

Fifth Sand, Allegheny and Washington Counties, Pa.

The Fifth sand of Upper Devonian age is one of the most important sands in the Appalachian region. It was the most productive horizon in the famous McDonald pool, in which a single well is credited with a total yield of more than 2,000,000 barrels. In Allegheny and Washington Counties, Pa., the Fifth sand averages between 10 and 35 feet in thickness, and like most of the Appalachian oil sands varies considerably in porosity in nearby areas. The wells range between 2,200 and 2,500 feet in depth.

ESTIMATED FUTURE PRODUCTION TABLE—FIFTH SAND.

Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
50	0	300	2,500	800	5,550
100	700	400	3,250	900	6,050
150	1,200	500	3,850	1,000	6,500
200	1,700	600	4,450	1,250	7,600
250	2,100	700	5,000	1,500	8,500

Gordon Sand, Allegheny County, Pa.

The wells average 2,100 feet in depth. The Gordon sand is of Upper Devonian age.

ESTIMATED FUTURE PRODUCTION TABLE—GORDON SAND IN ALLEGHENY COUNTY, PA.

Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
50	0	300	1,300	800	3,450
100	250	400	1,750	900	3,800
150	500	500	2,250	1,000	4,200
200	750	600	2,700	1,250	5,050
250	1,050	700	3,100	1,500	5,800

Gordon Sand, Greene County, Pa.

The Gordon is one of the main producing sands in Greene County. The average depth of wells is 3,000 feet, and the average thickness of the pay is 6 feet. The Gordon is of Upper Devonian age.

ESTIMATED FUTURE PRODUCTION TABLE—GORDON SAND IN GREENE COUNTY, PA.

Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
50	0	600	2,250	1,750	5,250
100	200	700	2,550	2,000	5,800
150	450	800	2,850	2,250	6,400
200	650	900	3,150	2,500	6,950
250	900	1,000	3,450	2,750	7,550
300	1,100	1,250	4,050	3,000	8,100
400	1,500	1,500	4,650	3,500	9,200
500	1,900				

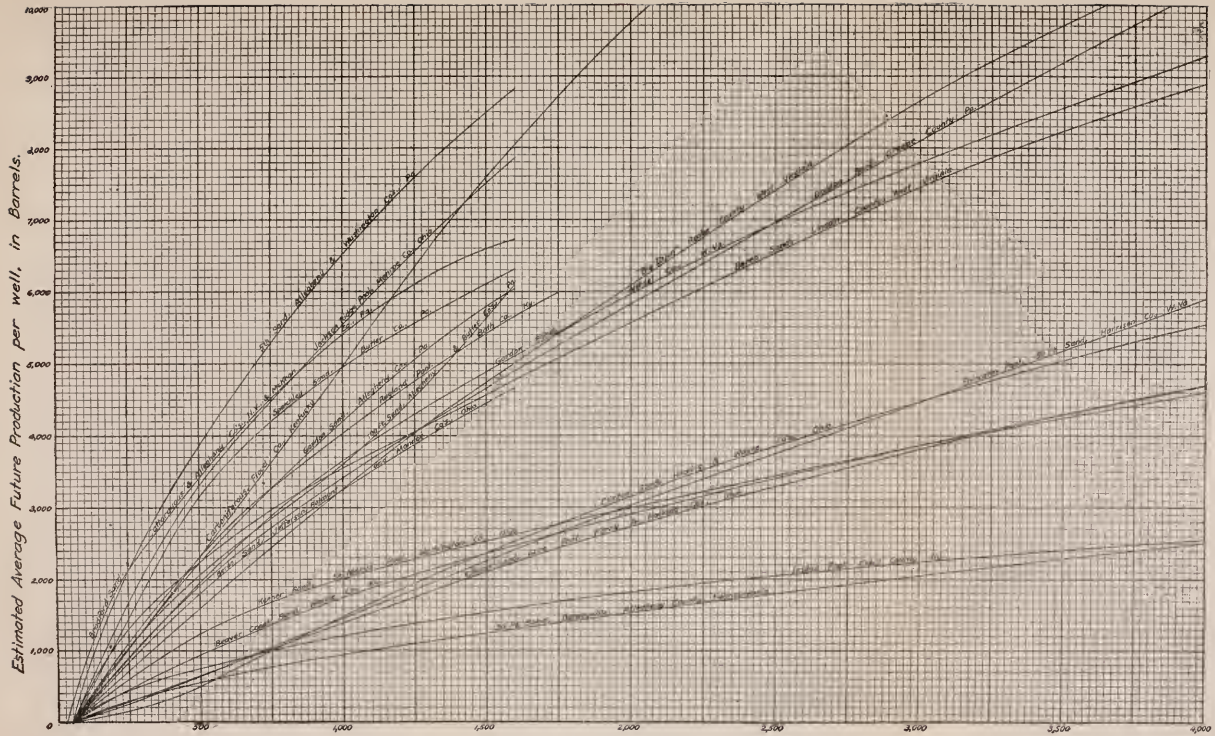


FIG. 4.—ESTIMATED AVERAGE FUTURE PRODUCTION CURVES, APPALACHIAN FIELD.

(To face page 99.)

Fifty-foot Sand, Shinnston Pool, Harrison County, W. Va.

This pool is credited with having some of the wells of largest initial production in West Virginia. A few are reported coming in at a rate between 450 and 550 barrels an hour. The pool underlies an irregular area of 1,530 acres, situated on a terrace on the western flank of the Chestnut Ridge anticline. Production is from the 50-foot sand. The pay streak is of Upper Devonian age and is of variable thickness and porosity, and averages possibly 15 feet. Wells are between 2,000 and 2,300 feet in depth, and for the entire pool have an average spacing of 10.7 acres per well. Individual tracts have produced at the rate of 22,000 barrels per acre. A single well has yielded more than 165,000 barrels. A total production curve for the entire pool indicates that it is more than 90 per cent exhausted. The oil has a specific gravity of 0.797 (45.5° B.).

ESTIMATED FUTURE PRODUCTION TABLE—SHINNSTON POOL.

Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
50	0	800	1,100	2,750	4,100
100	50	900	1,300	3,000	4,450
150	150	1,000	1,450	3,500	5,200
200	200	1,250	1,900	4,000	5,900
250	250	1,500	2,250	4,500	6,550
300	350	1,750	2,650	5,000	7,250
400	500	2,000	3,050	6,000	8,500
500	650	2,250	3,400	7,000	9,500
600	800	2,500	3,750	7,500	9,850
700	950				

Big Injun Sand, Roane County, W. Va.

The Big Injun sand future production curve is based on the records of tracts situated in different parts of Roane County, W. Va. The sand averages about 40 feet in thickness and the pay possibly about 10 feet. The Big Injun sand is of Lower Car-

Fifty-foot Sand, Shinnston Pool, Harrison County, W. Va.

This pool is credited with having some of the wells of largest initial production in West Virginia. A few are reported coming in at a rate between 450 and 550 barrels an hour. The pool underlies an irregular area of 1,530 acres, situated on a terrace on the western flank of the Chestnut Ridge anticline. Production is from the 50-foot sand. The pay streak is of Upper Devonian age and is of variable thickness and porosity, and averages possibly 15 feet. Wells are between 2,000 and 2,300 feet in depth, and for the entire pool have an average spacing of 10.7 acres per well. Individual tracts have produced at the rate of 22,000 barrels per acre. A single well has yielded more than 165,000 barrels. A total production curve for the entire pool indicates that it is more than 90 per cent exhausted. The oil has a specific gravity of 0.797 (45.5° B.).

ESTIMATED FUTURE PRODUCTION TABLE—SHINNSTON POOL.

Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
50	0	800	1,100	2,750	4,100
100	50	900	1,300	3,000	4,450
150	150	1,000	1,450	3,500	5,200
200	200	1,250	1,900	4,000	5,900
250	250	1,500	2,250	4,500	6,550
300	350	1,750	2,650	5,000	7,250
400	500	2,000	3,050	6,000	8,500
500	650	2,250	3,400	7,000	9,500
600	800	2,500	3,750	7,500	9,850
700	950				

Big Injun Sand, Roane County, W. Va.

The Big Injun sand future production curve is based on the records of tracts situated in different parts of Roane County, W. Va. The sand averages about 40 feet in thickness and the pay possibly about 10 feet. The Big Injun sand is of Lower Car-

boniferous age and is found in this county at an average depth of 2,000 feet.

ESTIMATED FUTURE PRODUCTION TABLE, BIG INJUN SAND, ROANE COUNTY, W. VA.

Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
50	0	600	1,950	1,750	5,400
100	200	700	2,300	2,000	6,100
150	400	800	2,600	2,250	6,750
200	550	900	2,950	2,500	7,400
250	750	1,000	3,250	2,750	8,050
300	900	1,250	4,050	3,000	8,650
400	1,250	1,500	4,750	3,500	9,700
500	1,600				

Berea Sand, Lincoln County, W. Va.

The wells tapping the Berea sands in Lincoln County, W. Va., range from 2,000 to 2,600 feet in depth, and the sand averages possibly 20 feet in thickness. The Berea sand is of Lower Carboniferous age.

ESTIMATED FUTURE PRODUCTION TABLE, BEREA SAND, LINCOLN COUNTY, W. VA.

Average Production per Well During Last Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Last Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Last Taxable Year.	Estimated Average Future Production per Well.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
50	0	600	2,600	2,000	5,550
100	450	700	2,850	2,250	6,050
150	750	800	3,100	2,500	6,550
200	1,050	900	3,350	2,750	7,000
250	1,300	1,000	3,550	3,000	7,450
300	1,500	1,250	4,050	3,500	8,250
400	1,900	1,500	4,600	4,000	8,900
500	2,250	1,750	5,100		

Gordon Sand, Wetzel County, W. Va.

The Gordon sand is the source of much oil in Wetzel County. The average depth of wells is 3,100 feet and the average thickness of the pay is 7 feet. The Gordon sand is of Upper Devonian age.

ESTIMATED FUTURE PRODUCTION TABLE, GORDON SAND IN WETZEL COUNTY, W. VA.

Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
50	0	600	2,350	2,000	5,950
100	250	700	2,700	2,250	6,500
150	450	800	3,050	2,750	7,400
200	700	900	3,350	3,000	7,800
250	900	1,000	3,650	3,500	8,550
300	1,150	1,250	4,250	4,000	9,300
400	1,550	1,500	4,900		
500	1,950	1,750	5,400		

Berea Sand, Jefferson, Belmont, and Monroe Counties, Ohio.

Only a few records of Berea sand production extending over a number of years were obtained in eastern Ohio. The curve shown is based on the records of properties situated in Jefferson, Belmont, and Monroe Counties. The pay sand is about 20 feet thick and the wells range from 1,400 to 2,000 feet in depth.

ESTIMATED FUTURE PRODUCTION TABLE, BEREA SAND IN JEFFERSON, BELMONT, AND MONROE COUNTIES, OHIO.

Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
50	0	300	1,050	800	2,725
100	200	400	1,450	900	3,000
150	450	500	1,800	1,000	3,500
200	650	600	2,150	1,250	3,850
250	850	700	2,450	1,500	4,450

Keener Sand, Jackson Ridge Pool Monroe County, Ohio.

The sand is between 25 and 40 feet thick and the pay averages 12 feet. The wells are not large producers, but they have "good staying qualities." They average 1,450 feet in depth. The Keener sand is of Lower Carboniferous age.

ESTIMATED FUTURE PRODUCTION TABLE—JACKSON RIDGE POOL.

Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
50	0	300	2,050	800	4,700
100	450	400	2,700	900	5,100
150	900	500	3,300	1,000	5,550
200	1,275	600	3,800	1,250	6,550
250	1,650	700	4,250	1,500	7,500

Keener Sand. St. Mary's Pool, Washington County. Ohio.

The pay is 8 feet thick and the wells average 1,650 feet in depth.

ESTIMATED FUTURE PRODUCTION TABLE—ST. MARY'S POOL.

Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
50	0	800	1,700	2,750	3,650
100	150	900	1,850	3,000	3,850
150	300	1,000	2,000	3,500	4,250
200	450	1,250	2,300	4,000	4,600
250	600	1,500	2,550	4,500	4,955
300	750	1,750	2,750	5,000	5,200
400	1,000	2,000	3,000	6,000	5,750
500	1,250	2,250	3,200	7,000	6,220
600	1,400	2,500	3,450	8,000	6,700
700	1,600				

Clinton Sand, Gore Pool, Perry and Hocking Counties, Ohio.

The Gore pool in the Clinton sand in Perry and Hocking Counties, Ohio, was opened up in 1911. It is a westward extension of the New Straitsville pool. Up to 1918, 134 wells had been drilled in the Gore pool with an average spacing of approximately 10 acres per well. The pay sand ranges from 3 to 25 feet in thickness and averages about 15 feet. The wells are between 2,900 and 3,300 feet deep. The oil has a gravity of 46° Baumé. The Clinton sand is of Silurian age.

ESTIMATED FUTURE PRODUCTION TABLE—GORE POOL.

Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
50	0	800	1,100	2,750	3,550
100	50	900	1,250	3,000	3,800
150	150	1,000	1,400	3,500	5,300
200	200	1,250	1,750	4,000	4,700
250	300	1,500	2,100	4,500	5,100
300	350	1,750	2,450	5,000	5,500
400	500	2,000	2,750	6,000	6,200
500	650	2,250	3,000	7,000	6,900
600	800	2,500	3,300	8,000	7,550
700	950				

Clinton Sand, Wayne and Hocking Counties, Ohio

The walls vary in depth between 3,000 and 3,500 feet and the average thickness of the pay sand is 20 feet. The Clinton sand is of Silurian age.

ESTIMATED FUTURE PRODUCTION TABLE—CLINTON SAND, HOCKING AND WAYNE COUNTIES, OHIO.

Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
50	0	800	1,100	2,750	4,200
100	50	900	1,300	3,000	4,450
150	75	1,000	1,450	3,500	5,050
200	100	1,250	1,950	4,000	5,550
250	150	1,500	2,350	4,500	6,050
300	200	1,750	2,750	5,000	6,500
400	350	2,000	3,150	6,000	7,400
500	500	2,250	3,550	7,000	8,200
600	700	2,500	3,850	8,000	8,900
700	900				

Ragland Field, Bath County, Ky.

The field was discovered in 1900 and was mainly drilled up by 1904, though occasional sporadic drilling is still done. The sand is the Corniferous limestone of Devonian age, which averages from 12 to 20 feet in thickness. Its depth is 300 to 380 feet in the Licking River Valley and 500 feet more on the hilltops. The oil occurs in a flat anticline with northeast-southwest axis and with the oil in that portion of the sand lying between 250 and 300 feet above sea level. The general dip of the rock is to the southeast, and a few miles to the northwest of the field the oil sand crops out at the surface. These is very little gas with the oil. The gravity is about 26° to 27° Baumé.

ESTIMATED FUTURE PRODUCTION TABLE—RAGLAND POOL

Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
50	0	400	1,850	1,000	4,050
100	300	500	2,300	1,250	4,750
150	600	600	2,750	1,500	5,400
200	850	700	3,100	1,750	6,000
250	1,100	800	3,450	2,000	6,400
300	1,400	900	2,750	3,000	6,900

Floyd County, Ky.

The future production curve of Floyd County, Ky., is based on production from properties representing several sands of Carboniferous age. These are the Beaver, Horton, Pike or Mason, and the Salt sands. There are no pronounced surface structures; oil and gas moving northwestward up the dip have apparently been stopped either by slight terraces or by tight places in the sand. Dry holes are numerous. Initial production is small but is well maintained. The gravity is about 40° Baumé.

ESTIMATED FUTURE PRODUCTION CURVE, FLOYD COUNTY, KY.

Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
50	0	400	1,800	1,000	4,950
100	250	500	2,300	1,250	6,300
150	500	600	2,850	1,500	7,600
200	750	700	3,400	1,750	8,700
250	1,050	800	3,900	2,000	9,750
300	1,300	900	4,450		

Beaver Creek Sand, Wayne County, Ky.

The Wayne County field consists of a number of small pools to which separate local names are given. The earliest wells were drilled between 20 and 25 years ago, and some drilling is still going on. The principal oil-bearing horizon is a cherty geodal limestone known as the Beaver Creek sand. It lies just above the Chattanooga shale and forms the basal number of the Waverly or Mississippian. This limestone varies greatly in thickness, texture, and porosity, and the production of wells varies accordingly. It lies 400 to 600 feet beneath the valleys, while the hills rise from 300 to 600 feet higher. Structurally the oil favors the sides and bottoms of synclinal troughs that slope gently eastward.

ESTIMATED FUTURE PRODUCTION TABLE,
WAYNE COUNTY, KY.

Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
50	0	800	1,450	3,000	3,850
100	100	900	1,600	3,500	4,300
150	250	1,000	1,750	4,000	4,700
200	350	1,250	2,050	4,500	5,100
250	450	1,500	2,350	5,000	5,450
300	550	1,750	2,650	6,000	6,200
400	750	2,000	2,900	7,000	6,900
500	950	2,250	3,150	8,000	7,600
600	1,150	2,500	3,400		
700	1,300	2,750	3,600		

Irvine Field, Estill County, Ky.

The Irvine field extends from near Irvine, Estill County, Ky., northeastward 12 miles and is 1 to 2 miles wide. Present evelopment began in 1915. The field lies on the southeast of a fault from which the rocks dip to the southeast. The producing sand is a

ESTIMATED FUTURE PRODUCTION TABLE—IRVINE POOL.

Average Production per Well During Last Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Last Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Last Taxable Year.	Estimated Average Future Production per Well.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
50	0	800	1,000	3,000	2,250
100	150	900	1,100	3,500	2,400
150	250	1,000	1,200	4,000	2,550
200	350	1,250	1,350	4,500	2,650
250	450	1,500	1,550	5,000	2,750
300	500	1,750	1,700	6,000	2,950
400	650	2,000	1,800	7,000	3,100
500	750	2,250	1,950	8,000	3,200
600	850	2,500	2,050		
700	950	2,750	2,150		

porous magnesian limestone of Corniferous (Devonian) age, with the pay usually in the upper few feet. The sand near Irvine is about 20 to 30 feet thick and lies only 100 to 200 feet beneath the surface of the valleys, but in the hills 600 to 800 feet deeper. The gravity of the oil is about 33° Baumé.

FUTURE PRODUCTION CURVES FOR LIMA-INDIANA AND ILLINOIS-INDIANA FIELDS.

The Lima-Indiana field comprises about 230,000 acres in northwestern Ohio and about 41,000 acres in northeastern Indiana. The productive areas in this field occur in low domes over the broad crest of the Cincinnati uplift, or in domes or terraces or other minor convexities on its flanks. The oil is obtained from lenses or discontinuous layers in the Trenton limestone, where the original limestone has been changed to a porous dolomite, at depths varying with the distance from the crest of the arch, with the dip of strata, and the depth below the top of the formation. Wherever the Trenton limestone ceases to be dolomitic it ceases to be oil bearing. This Trenton limestone is from 450 to 600 feet thick, and the oil is usually found within 100 feet of the top, although in a few places, as in Grant and Delaware Counties, Ind., and Seneca County, Ohio, oil has been found as low as 250 to 400 feet in the Trenton. The best pay, however, is generally believed to be less than 40 feet below the top of the formation. Often two pay streaks occur in the upper part of the Trenton, the first 10 to 15 feet below the top and the second about 20 feet lower. It seems that the productive lenses found at greater depth do not occur at definite levels.

The existence of oil in the Trenton limestone of Ohio was discovered in 1885 and many wells were drilled the following year. The earlier developments were at Findlay in Hancock County, North Baltimore in Wood County, and Lima in Allen County. The greater part of the production has come from Wood, Sandusky, and Hancock Counties, but Allen, Mercer, Auglaize, Lucas, Ottawa, Seneca, Van Wert, and Darke Counties have also contributed important quantities.

The finding of oil in northwest Ohio in 1885 stimulated prospecting farther west in Indiana. In 1889 two producing wells were drilled in Blackford County and in 1890 several wells were brought in in Wells County, and from that date the field was rapidly ex-

tended. The greater part of the Trenton oil production in Indiana has come from Adams, Blackford, Delaware, Grant, Huntington, Jay, Randolph, and Wells Counties. Of these, Grant County has been, perhaps, the greatest producer.

The pools in the Trenton rock district are very irregular in shape, differ greatly in size, and often entirely surround barren areas. While, of course, the varying characteristics of the pools do not follow arbitrary lines, it was found best in making a study of this district to make each county a pool unit.

The main Illinois-Indiana field is about 70 miles long and has a maximum width of about 20 miles. It extends in a slightly northwest-southeast direction from the vicinity of Westfield in northwestern Clark County through Clark, Crawford, and Lawrence Counties to the neighborhood of St. Francisville. These are outliers or extensions in Coles, Cumberland, and Jasper Counties, but the three first named have produced by far the greater portion of the oil.

In Indiana the field extends across the Wabash River into Gibson, Pike, and Sullivan Counties.

Nearly all the production is found in structural undulations on the east flank of the La Salle anticline, which begins near La Salle in the northern part of the State and follows generally the trend of production as given above. This great arch is asymmetrical, the western limb being much more steeply inclined than the eastern. In the southern part of Lawrence County it appears to flatten out, and a few miles below St. Francisville it breaks up and disappears.

Development in eastern Illinois began with a well drilled near Casey, in Clark County, which produced about 35 barrels a day from a sand found at a depth of less than 400 feet. This was in 1904, and by the end of 1905 more than a thousand barrels a day were being marketed. From this on development has been rapid.

The producing sands in the north end of the field are shallow, occurring in the Pennsylvanian series at depths of from 300 to 400 feet. Farther south productive sands are found much lower stratigraphically, and lie at greater depths—the deeper ones occurring in the Chester and St. Genevieve (Upper Mississippian) formations.

The richest oil-producing area in the field is in Lawrence County where seven sands are encountered at depths ranging from 450 to 2,000 feet, with the richest sand on the bottom.

Besides the field on the slopes of the La Salle anticline there are three or four minor pools on the western side of the great Illinois basin—those of Sandoval in Marion County, and Carlyle in Clinton County, perhaps being the best known. Besides those there are the Allendale pool in Wabash County and the Colmar pool in McDonough County which have produced considerable quantities of oil.

Productive areas, like those elsewhere, are irregular in shape and of varying characteristics. It was found that separation into county "pool units" as in the Lima-Indiana field was not feasible, as there are sometimes two or three variant pools in a county. In some cases, however, as in Crawford County, two or three or more "pools" of the same general character were combined into one.

In Clark County there are two pools, both in the shallow Pennsylvanian sands—the Westfield pool on the north and the Johnson Township pool south and east of the Westfield. Immediately to the southwest of the Westfield pool and west of the Johnson Township pool lies the Siggins pool, which is almost all in Cumberland County.

In Crawford County are a number of small pools without much difference, and of these have been grouped together the Robinson, Kibbie, Oblong, Honey Creek, and Hardinsville, under the name "Robinson pool." In southeast Crawford County there are three outlying pools, Duncanville, Flat Rock, and Birds, which have been grouped together under the name of Birds-Flat Rock pool.

In Lawrence County all the pools in the upper part of the county, Nuttall, Applegate, Bridgeport, Lawrenceville, etc., have been grouped as the Upper Lawrence County pool, and in the south are the Kirkwood and Dennison pools.

Other pools in Illinois are the Plymouth or Colmar pool in McDonough County, the Sandoval pool in Marion County, the Carlyle pool in Clinton County, and the Allendale pool in Wabash County.

The work preparatory to the construction of estimated future production curves in the producing areas in the Lima-Indiana and Illinois-Indiana fields consisted in the inspection of all available production records and the selection of those considered typical of the various pools and localities, the tabulation of these records, drawing of decline curves for individual leases, and finally the com-

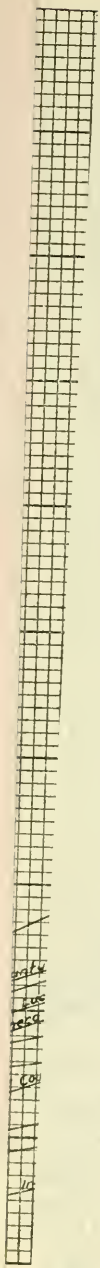
bination of all these decline curves into an average decline curve for the field or pool.

In the Lima-Indiana field were found very few records of production prior to 1908. Some companies had never kept proper records and other had destroyed all their old books, so the work was somewhat handicapped in this regard. However, the production records for the past 10 years were very full and complete, and it is on these records that curves are based.

The " average well " was adopted as the unit for tabulation and estimating and the " average decline curve," which seems to meet all the requirements of the situation, was devised for use in extending the individual lease production curves to their limit of profitable production, and also in constructing the estimated future production curve.

In the Illinois-Indiana field, which is younger than the Lima-Indiana field, were found excellent production records from the early life of the field. The same methods in handling the records were used as in the Lima-Indiana field and the same kind of curves drawn.

In all the records of more than 2,000 leases, comprising about 40 per cent of the producing area, were tabulated and studied and the resultant curves as presented herewith are believed to be fairly representative.



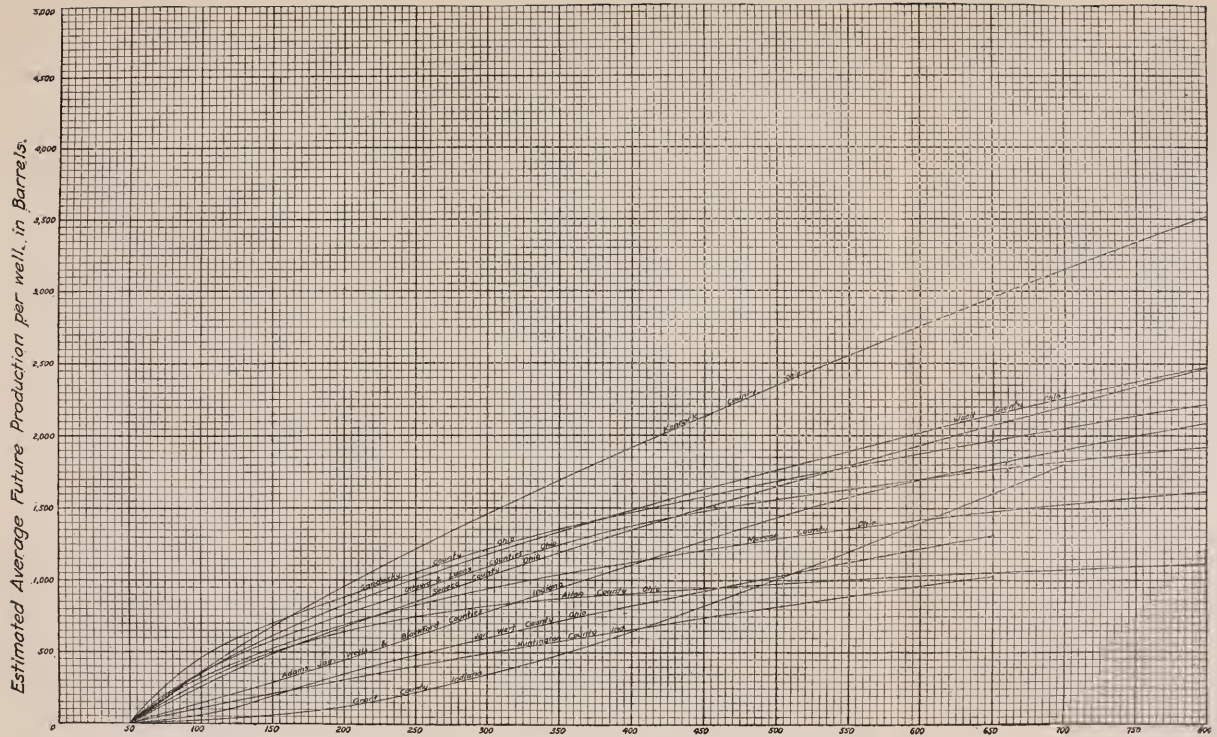


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FIG. 5.—ESTIMATED AVERAGE FUTURE PRODUCTION CURVES, LIMA-INDIANA FIELD.

(To face page 110.)

TABLES FOR ESTIMATION OF FUTURE PRODUCTION.

Sandusky County, Ohio.

Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year	Estimated Average Future Production per Well.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
50	0	350	1,350	650	1,970
100	450	400	1,470	700	2,055
150	700	450	1,575	750	2,150
200	875	500	1,680	800	2,230
250	1,050	550	1,775		
300	1,200	600	1,875		

Ottawa and Lucas Counties, Ohio.

50	0	350	1,230	650	1,760
100	350	400	1,370	700	1,820
150	575	450	1,470	750	1,875
200	765	500	1,555	800	1,920
250	930	550	1,625		
300	1,085	600	1,695		

Wood County, Ohio.

50	0	400	1,480	1,000	2,875
100	350	450	1,625	1,100	3,055
150	600	500	1,760	1,200	3,250
200	825	600	2,015	1,300	3,425
250	1,010	700	2,255	1,400	3,600
300	1,175	800	2,475	1,500	3,780
350	1,330	900	2,675	1,550	3,950

Seneca County, Ohio.

75	0	450	1,500	850	1,625
100	260	500	1,640	900	2,750
150	480	550	1,785	950	2,875
200	675	600	1,930	1,000	3,015
250	870	650	2,075	1,050	3,140
300	1,025	700	2,220	1,100	3,260
350	1,175	750	2,350	1,150	3,400
400	1,350	800	2,475	1,200	3,520

TABLES FOR ESTIMATION OF FUTURE PRODUCTION.

Sandusky County, Ohio.

Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year	Estimated Average Future Production per Well.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
50	0	350	1,350	650	1,970
100	450	400	1,470	700	2,055
150	700	450	1,575	750	2,150
200	875	500	1,680	800	2,230
250	1,050	550	1,775		
300	1,200	600	1,875		

Ottawa and Lucas Counties, Ohio.

50	0	350	1,230	650	1,760
100	350	400	1,370	700	1,820
150	575	450	1,470	750	1,875
200	765	500	1,555	800	1,920
250	930	550	1,625		
300	1,085	600	1,695		

Wood County, Ohio.

50	0	400	1,480	1,000	2,875
100	350	450	1,625	1,100	3,055
150	600	500	1,760	1,200	3,250
200	825	600	2,015	1,300	3,425
250	1,010	700	2,255	1,400	3,600
300	1,175	800	2,475	1,500	3,780
350	1,330	900	2,675	1,550	3,950

Seneca County, Ohio.

75	0	450	1,500	850	1,625
100	260	500	1,640	900	2,750
150	480	550	1,785	950	2,875
200	675	600	1,930	1,000	3,015
250	870	650	2,075	1,050	3,140
300	1,025	700	2,220	1,100	3,260
350	1,175	750	2,350	1,150	3,400
400	1,350	800	2,475	1,200	3,520

TABLES FOR ESTIMATION OF FUTURE PRODUCTION—*Cont.*

Hancock County, Ohio.

Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
50	0	250	1,215	450	2,130
100	360	300	1,450	500	2,350
150	670	350	1,685		
200	950	400	1,910		

Allen County, Ohio.

50	0	175	570	300	825
75	160	200	640	325	850
100	300	225	700	350	870
125	405	250	760	375	890
150	490	275	795	400	905

Mercer County, Ohio.

50	0	350	1,030	650	1,475
100	320	400	1,120	700	1,525
150	525	450	1,205	750	1,580
200	690	500	1,285	800	1,630
250	825	550	1,350		
300	940	600	1,415		

Van Wert County, Ohio.

50	0	125	120	200	350
75	20	150	195	225	420
100	60	175	280	250	490

Adams, Jay, and Blackford Counties, Ind.

50	0	350	950	800	2,080
100	125	400	1,120	900	2,210
150	290	450	1,275	1,000	2,325
200	450	500	1,425	1,100	2,420
250	600	600	1,700	1,200	2,475
300	775	700	1,925		

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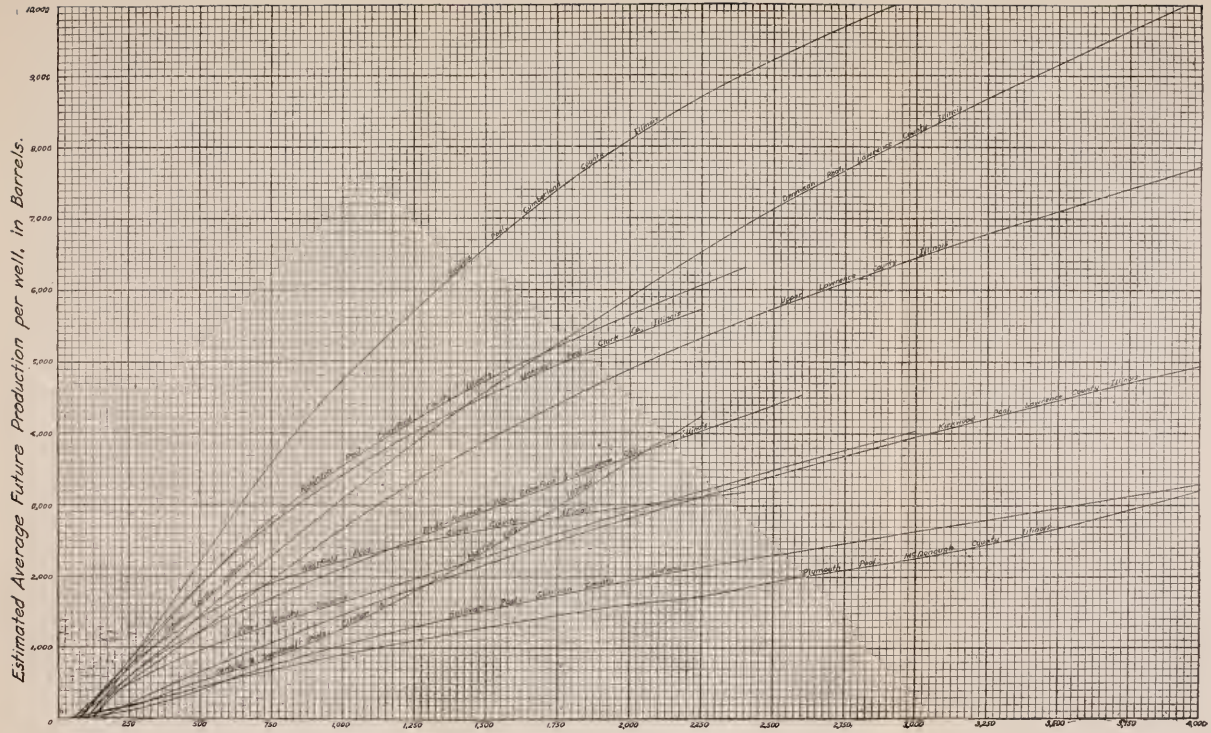
Estimated Average Future Production per well, in Barrels.
Average Production per well during Taxable Year, in Barrels.
0
1,000
2,000
3,000
4,000
5,000
6,000
7,000
8,000
9,000
10,000
250
500
750
1,000
1,250
1,500
1,750
2,000
2,250
2,500
2,750
3,000
3,250
3,500
3,750
4,000
Robinson Sand
Clark County, Illinois
Darwood and Robinson Sands
Lawrence County, Illinois
Robinson Sand
Lawrence County, Illinois
Robinson Sand
Clark County, Illinois
Robinson Sand
Crawford County, Illinois
Robinson Sand
Crawford County, Illinois
Robinson Sand
Crawford

TABLES FOR ESTIMATION OF FUTURE PRODUCTION.—*Cont.*

GRANT COUNTY, IND.

Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
50	0	300	340	550	1,200
100	20	350	480	600	1,400
150	60	400	650	650	1,610
200	135	450	820	700	1,800
250	220	500	1,010		

HUNTINGTON COUNTY, IND.

50	0	155	210	250	405
75	80	175	260	275	450
100	110	200	305	300	495
125	160	225	355		

CARLYLE AND SANDOVAL POOLS, CLINTON AND MARION COUNTIES, ILL.

50	0	350	280	1,250	1,800
100	50	400	340	1,500	2,375
150	90	450	400	1,750	2,975
200	140	500	460	2,000	3,600
250	175	750	840	2,250	4,250
300	230	1,000	1,280	2,400	4,650

WESTFIELD POOL, CLARK COUNTY, ILL.

75	0	400	1,190	1,000	2,225
100	150	450	1,300	1,250	2,470
150	375	500	1,420	1,500	2,660
200	575	600	1,640	1,750	2,840
250	750	700	1,825	2,000	2,990
300	900	800	1,975	2,250	3,120
350	1,050	900	2,120		

TABLES FOR ESTIMATION OF FUTURE PRODUCTION.—*Cont.*

GRANT COUNTY, IND.

Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
50	0	300	340	550	1,200
100	20	350	480	600	1,400
150	60	400	650	650	1,610
200	135	450	820	700	1,800
250	220	500	1,010		

HUNTINGTON COUNTY, IND.

50	0	155	210	250	405
75	80	175	260	275	450
100	110	200	305	300	495
125	160	225	355		

CARLYLE AND SANDOVAL POOLS, CLINTON AND MARION COUNTIES, ILL.

50	0	350	280	1,250	1,800
100	50	400	340	1,500	2,375
150	90	450	400	1,750	2,975
200	140	500	460	2,000	3,600
250	175	750	840	2,250	4,250
300	230	1,000	1,280	2,400	4,650

WESTFIELD POOL, CLARK COUNTY, ILL.

75	0	400	1,190	1,000	2,225
100	150	450	1,300	1,250	2,470
150	375	500	1,420	1,500	2,660
200	575	600	1,640	1,750	2,840
250	750	700	1,825	2,000	2,990
300	900	800	1,975	2,250	3,120
350	1,050	900	2,120		

TABLES FOR ESTIMATION OF FUTURE PRODUCTON—*Cont.*

JOHNSON POOL, CLARK COUNTY, ILL.

Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
75	0	400	1,475	1,000	3,440
100	100	450	1,700	1,250	4,025
150	350	500	1,880	1,500	4,500
200	600	600	2,250	1,750	4,950
250	820	700	2,600	2,000	5,360
300	1,025	800	2,900	2,250	5,740
350	1,250	900	3,170		

SIGGINS POOL, CUMBERLAND COUNTY, ILL.

75	0	1,000	4,750	3,500	11,000
100	100	1,250	5,700	4,000	11,950
200	550	1,500	6,000	4,500	12,900
300	1,000	1,750	7,400	5,000	14,000
400	1,600	2,000	8,100	6,000	16,000
500	2,200	2,500	9,200	7,000	17,750
750	3,600	3,000	10,175	8,000	19,150

ROBINSON POOL, CRAWFORD COUNTY, ILL.

100	0	450	1,650	1,250	4,200
150	240	500	1,850	1,500	4,725
200	500	600	2,275	1,750	5,200
250	750	700	2,625	2,000	5,650
300	975	800	2,950	2,250	6,075
350	1,200	900	3,275		
400	1,450	1,000	3,550		

BIRDS-FLATROCK POOL, CRAWFORD COUNTY, ILL.

100	0	450	1,125	1,250	2,525
150	350	500	1,240	1,500	2,910
200	450	600	1,450	1,750	3,300
250	600	700	1,625	2,000	3,675
300	750	800	1,800	2,250	4,035
350	890	900	1,975	2,500	4,440
400	1,020	1,000	2,135	2,750	4,750

TABLES FOR ESTIMATION OF FUTURE PRODUCTION—*Cont.*

Upper Lawrence County, Ill.

Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
150	0	6,000	10,800	18,000	39,000
500	1,250	7,000	12,500	20,000	44,500
1,000	2,750	8,000	14,400	22,000	48,000
1,500	4,000	9,000	16,400	24,000	53,000
2,000	5,000	10,000	18,500	26,000	56,500
3,000	6,500	12,000	23,000	28,000	59,750
4,000	7,700	14,000	28,000	30,000	62,600
5,000	9,200	16,000	33,400	32,000	65,000

Kirkwood Pool, Lawrence County, Ill.

150	0	1,250	1,840	4,000	4,940
200	100	1,500	2,200	4,500	5,400
300	275	1,750	2,500	5,000	5,800
400	450	2,000	2,825	6,000	6,650
500	625	2,500	3,400	7,000	7,450
750	1,040	3,000	3,970	8,000	8,225
1,000	1,470	3,500	4,470		

Dennison Pool, Lawrence County, Ill.

150	0	6,000	13,400	18,000	41,000
500	1,500	7,000	15,000	20,000	46,700
1,000	3,000	8,000	17,000	22,000	52,000
1,500	4,500	9,000	19,000	24,000	56,700
2,000	6,000	10,000	21,000	26,000	60,700
3,000	8,200	12,000	25,500	28,000	64,000
4,000	10,000	14,000	30,400	30,000	67,000
5,000	11,800	16,000	35,500	32,000	69,800

Plymouth Pool, McDonough County, Ill.

50	0	450	400	1,500	1,275
100	50	500	450	1,750	1,460
150	100	600	550	2,000	1,630
200	150	700	640	2,500	1,950
250	200	800	725	3,000	2,200
300	250	900	820	4,000	3,200
350	300	1,000	900	5,000	4,500
400	350	1,250	1,100		

TABLES FOR ESTIMATION OF FUTURE PRODUCTION—*Cont.*

Gibson County, Ind.

Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
50	0	300	885	550	1,775
100	175	350	1,065	600	1,950
150	355	400	1,240	650	2,130
200	530	450	1,425	700	2,310
250	710	500	1,600		

Pike County, Ind.

50	0	650	1,175	1,500	2,290
100	125	700	1,250	1,600	2,420
150	250	750	1,325	1,700	2,550
200	375	800	1,380	1,800	2,660
250	500	850	1,450	1,900	2,780
300	600	900	1,520	2,000	2,900
350	700	950	1,590	2,200	3,140
400	800	1,000	1,650	2,400	3,370
450	890	1,100	1,775	2,600	3,600
500	960	1,200	1,920	2,800	3,825
550	1,040	1,300	2,020	3,000	4,050
600	1,100	1,400	2,170	3,200	4,250

Sullivan Pool, Sullivan County, Ind.

50	0	600	550	1,750	1,750
100	10	700	675	2,000	1,940
150	40	800	800	2,250	2,125
200	60	900	925	2,500	2,300
250	100	1,000	1,040	2,750	2,475
300	150	1,100	1,150	3,000	2,640
350	200	1,200	1,250	3,250	2,800
400	275	1,300	1,335	3,500	2,970
450	350	1,400	1,430	3,750	3,125
500	410	1,500	1,525	4,000	3,280

FUTURE PRODUCTION CURVES MID-CONTINENT DISTRICT.

The oil fields of the Mid-Continent Division are situated in a broad belt extending from near Kansas City, south through eastern Kansas and northeastern Oklahoma, thence southwest through south-central Oklahoma into northwest Texas as far as Brownwood. Pools are scattered throughout this area and new pools are being discovered from time to time. Nearly all pools are located on geologic structures that are well defined at the surface. With the exception of a few pools of minor importance in southern Oklahoma and in Texas, all production is from formations of Carboniferous age, the Pennsylvanian series being of most importance.

In general the formations dip to the west or northwest. There are numerous producing sands at various horizons, and in some fields there are several productive sands. The depths to production range from 200 feet to 3,500 feet, the shallow wells being generally along the eastern edge of the district and the deeper wells confined to the western portion. Most of the production comes from true sandstones with limestone as a secondary productive formation. The thicknesses of the sands range up to 300 feet (Healdton), but generally are between 25 and 75 feet.

The oil in the Mid-Continent Field is of paraffin base; from 30° Baumé to 45° Baumé in gravity, and averages about 35° Baumé. The original pressures in the gas and oil sands are roughly proportional with the depths. The recoveries per acre from the Oklahoma pools have been generally higher than in the eastern fields, but are less than for the Gulf coast and California. Wells are spaced from 2 acres per well to 12 acres per well, the average being about 6 acres per well.

The wells in the Mid-Continent Fields are drilled mostly by standard tools, rotary drilling being confined to a few fields in Texas and to fields in the red beds of Oklahoma. Drilling costs are greater than in the eastern fields, but less than for fields still farther west. The same statement holds true for producing costs, consequently the wells can not be pumped to such small productions as in the eastern fields, and unless the price of oil increases considerably in the future the wells will generally not have such long lives as in the eastern fields, because the greatest single factor in the longevity of wells is the smallest production to which a well can be pumped profitably. Artificial increasing of recovery is

limited practically to the use of vacuum pumps. This is common and has made notable effects on the productions of wells and also has been an important factor in extending the lives of the wells by making the operation of small wells more profitable.

The present investigation has brought to light, in the case of many of the smaller companies, a most amazing disregard for proper records of their operations, and a general lack of appreciation of the value of these was noted among most companies. It is believed that even the larger companies would find it profitable to get more detailed and accurate well and production records, and to make provision for their study and use. Most of the trouble in making estimates of future production could be traced to inadequate records, rather than to the so-called freak wells.

Only the average future production curves were prepared for publication. These show what may be expected on the average from wells within the district, to which each curve and table applies. This does not mean that every property will have the same future for wells of the same size, for it may vary from it considerably. If the producer does not work out the projection for each of his properties he can use the average curves as guides and know that, in most cases, his wells will approximate the figure given and are just as likely to be above as below the average figure. If the operator has a number of properties in the district, the general average will probably fall somewhere near the published curves. The possible variations are also distinctly limited and will rarely exceed certain maxima and minima for each district. This means that the so-called freaks are as the name implies, rare. In most fields they do not exceed 1 per cent and it is believed the number would be further reduced were it possible to check over each record to its source.

Where the production record is short, confused or incomplete, the taxpayer may be compelled to assume that his wells are average until later years when more adequate data are available. Where better production records can be obtained the taxpayer will find it desirable to work out the curves for each property and thus make closer estimates of its future. This is work for the qualified engineer or geologist though probably much can be done in future to simplify methods.

The average curves were made for certain fields or districts in accordance with, first, similar conditions; and second, the number

of usable production records. The end sought was to have enough records for each field to give a reliable average curve and at the same time to differentiate between fields whose average curves would differ materially. The districts were worked out by knowledge of the general conditions and by trial to determine whether the district could be subdivided advantageously or could be combined with some other field or district.

A refinement not possible in the present investigation was the working out of factors for readily judging how closely a particular property approaches the average curve. Much can be done with the data available by comparing the futures in relation to the chief factors affecting production in the mid-continent field, which are: First, thickness of sands or pay streak; second, porosity of sand; third, well depths; fourth, well spacing; fifth, manner of operation. By proper analysis of these factors it is believed convenient curves and tables can be worked out for making closer estimations.

Curves for the older and more developed fields such as Bartlesville were easily obtained, but difficulties were encountered in some of the other fields. In eastern Kansas, few records were obtainable and in many of the younger fields of the Mid-Continent, the records were few, short, and difficult to use. In some fields, sufficient data to make curves were not obtainable and the curves for others will have to be used until more data are available.

The north central Texas oil and gas field comprises the following counties: Jack, Throckmorton, Shackelford, Stephens, Palo Pinto, Parker, Erath, Eastland, Callahan, Taylor, Runnels, Coleman, Brown, Comanche, Mills, San Saba, McCulloch, and Concho. Production in this area is divided into several distinct pools, and the producing horizons are found in rocks ranging in age from late Mississippian or earliest Pennsylvanian through the Pennsylvanian and into the early Permian. The depth of the producing wells varies from less than 100 feet near Brownwood to more than 4,000 feet in Palo Pinto County.

Drilling has not yet progressed far enough to test out all the area, but several distinct pools have been outlined. The Avis shallow pool in northern Jack County, the Millsap pool in southwestern Parker County, the Grayford pool, the Mineral Wells gas pool and the Strawn pool in Palo Pinto County, the Desdemona and Sipe Springs pools in northern Comanche County, the Ranger and Allen pools in Eastland County, the Caddo, Breckenridge, and

Black pools in Stephens County, the South Bend pool in Young County, the Moran pool in Shackelford County, the Abilene pool in Taylor County, the Gray, Coleman, and Santa Anna pools in Coleman County, and the Brownwood pool in Brown County show the wide distribution of the producing areas. Of these pools, the most important, at present, are the Ranger, Brackenridge, Caddo, and Desdemona pools, where the oil is produced from the Bend formation of the late Mississippian or early Pennsylvanian age.

Because the development in this area has been recent and the production in many cases held back for lack of storage facilities, it was impossible to work out an average future production curve for the district or for an individual pool.

Eldorado District, Butler County, Kans.

The curves and tables for the Eldorado district were compiled from data submitted on leases within townships 25 and 26 south and ranges 4 and 5 east. Late in 1915, the first commercial producer was drilled to the Shallow sand in section 29, township 25 south, range 5 west. From this the pool was rapidly extended in all directions and the deeper sands developed, culminating in the discovery and exploitation of the 2,500 feet sand in the Towanda

ESTIMATED FUTURE PRODUCTION TABLE, ELDORADO DISTRICT, KANS.

Average Production per Well for Taxable Year.	Estimated Recoverable Underground Reserves.	Average Production per Well for Taxable Year.	Estimated Recoverable Underground Reserves.	Average Production per Well for Taxable Year.	Estimated Recoverable Underground Reserves.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
100	0	8,000	8,500	40,000	25,000
500	500	9,000	9,200	45,000	26,800
1,000	1,100	10,000	10,000	50,000	28,500
1,500	1,800	12,500	11,800	60,000	31,800
2,000	2,040	15,000	13,500	70,000	34,800
2,500	3,000	17,500	15,000	80,000	37,500
3,000	3,700	20,000	16,400	90,000	40,000
4,000	4,800	22,500	17,700	100,000	42,500
5,000	5,700	25,000	18,900	125,000	48,200
6,000	6,700	30,000	21,000	150,000	53,700
7,000	7,600	35,000	23,100		

district in the spring and summer of 1917. Water in the producing sands has been a serious menace and some wells, originally large producers, have been completely drowned out.

The structural geology of Butler county has been worked out in considerable detail and shows that production is confined to the tops and flanks of well-defined domes. Five producing sands are found at approximately depths of 660 feet, 750 feet, 850 feet, 1,850 feet, and 2,500 feet, respectively, and with thicknesses varying from 10 feet to 50 feet.

Augusta District, Butler County, Kans.

This district is included in townships 27, 28, and 29 south, range 4 west.

The field was discovered in June, 1914. The production is from a sand which is encountered at an average depth of 2,500 to 2,600 feet, and has an average thickness of approximately 30 feet.

The shallow sands, if they are present, are not productive.

ESTIMATED FUTURE PRODUCTION TABLE, AUGUSTA DISTRICT, KANSAS.

Average Production per Well for Taxable Year.	Estimated Recoverable Underground Reserves.	Average Production per Well for Taxable Year.	Estimated Recoverable Underground Reserves.	Average Production per Well for Taxable Year.	Estimated Recoverable Underground Reserves.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
500	0	10,000	10,750	70,000	45,400
1,000	750	15,000	15,000	80,000	48,750
2,000	2,000	20,000	19,000	90,000	51,700
3,000	3,200	25,000	22,500	100,000	54,500
4,000	4,500	30,000	25,750	110,000	57,000
5,000	5,500	35,000	28,800	120,000	59,000
6,000	6,750	40,000	31,800	130,000	61,000
7,000	7,800	45,000	34,750	140,000	62,750
8,000	8,800	50,000	37,300	150,000	64,200
9,000	9,800	60,000	41,750	160,000	65,800

Neodesha District, Wilson County, Kans.

The curve and tables for the Neodesha district were compiled from the data on leases lying within township 30 south, range 16 east. The productive area of the district covers a much larger

area, but since the records of the area were very incomplete elsewhere only the ones within the above-described township were used.

Discovery was made in this district about 1893 in a sand member of the Cherokee shales which is equivalent to the Bartlesville sand of Oklahoma. The sand in this district is encountered at an average depth of 800 to 820 feet and is 16 to 22 feet in thickness.

ESTIMATED FUTURE PRODUCTION, NEODESHA DISTRICT.

Average Production per Well for Taxable Year.	Estimated Recoverable Underground Reserves.	Average Production per Well for Taxable Year.	Estimated Recoverable Underground Reserves.	Average Production per Well for Taxable Year.	Estimated Recoverable Underground Reserves.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
150	0	1,200	5,150	3,200	6,660
200	950	1,300	5,280	3,400	6,750
250	1,600	1,400	5,425	3,600	6,850
300	2,100	1,500	5,530	3,800	6,940
350	2,500	1,600	5,640	4,000	7,030
400	2,850	1,700	5,730	4,200	7,120
450	3,125	1,800	5,810	4,400	7,220
500	3,350	1,900	5,900	4,600	7,300
600	3,725	2,000	5,975	4,800	7,390
700	4,050	2,200	6,100	5,000	7,480
800	4,325	2,400	6,250	6,000	7,925
900	4,575	2,600	6,350	7,000	8,300
1,000	4,780	2,800	6,450	8,000	8,700
1,100	4,975	3,000	6,560		

Bartlesville-Dewey District, Washington County, Okla.

The curves and tables are derived from property production records in all that part of Washington County lying in the townships 25–29 north and ranges 12–13 east. The area includes the Bartlesville, Dewey, Hogshooter, Copan, and Canary pools. The district is the oldest in Oklahoma, being opened in 1903, although most of the development, following the natural extension of work from Kansas southward into Indian Territory, began in 1904 and was pursued extensively in the three subsequent years. Several of the earlier records show wells of 300 to 400 barrels initial production. In later years, however, initial production is much smaller. Since the latter part of 1916 vacuum has been quite generally applied.

There are various producing oil and gas sands in the district, the principal ones being, with their average thickness and depth:

35 feet of Peru at 700 feet, 26 feet of Skinner at 1,050 feet, 32 feet of Bartlesville at 1,250 feet 34 feet of Burgess at 1,340 feet.

The average spacing of wells is about one to each 6 acres.

ESTIMATED FUTURE PRODUCTION TABLE, BARTLESVILLE-DEWEY, HOGSHOOTER DISTRICT.

Average Production per Well for Taxable Year.	Estimated Recoverable Underground Reserves per Well.	Average Production per Well for Taxable Year.	Estimated Recoverable Underground Reserves Per Well.	Average Production per Well for Taxable Year.	Estimated Recoverable Underground Reserves per Well.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
100	300	700	2,450	2,500	6,850
150	500	800	2,750	3,000	7,800
200	700	900	3,050	3,500	8,700
250	900	1,000	3,350	4,000	9,600
300	1,050	1,250	4,000	4,500	10,300
350	1,250	1,500	4,650	5,000	11,100
400	1,400	1,750	5,200	6,000	12,600
450	1,600	2,000	5,800	7,000	14,000
500	1,800	2,250	6,350	8,000	15,450
600	2,100				

Nowata District, Rogers and Nowata Counties, Okla.

The curves and tables for the Nowata district are made to cover townships 24 to 27 north, inclusive, and parts of ranges 15 to 17 east.

They include the shallow pools known as Chelsea, Alluwe, Coodys Bluff, Childers, Delaware, and Nowata. While conditions as to depth and sands vary somewhat in these pools, the curves apply to all the region.

Development was begun in the Coodys Bluff-Nowata-Alluwe region in 1904. In 1908 the Delaware, Childers region was developed.

The principal producing sand is the Bartlesville, found at depths varying (according to location) from 390 feet to something over 1,000 feet. The average depth in the Alluwe-Chelsea pool being 450 feet, at Coodys Bluff 525 feet, at Nowata 650 feet, near

Delaware 675 feet, in township 27 north, ranges 14 and 15 east, 940 feet. The thickness of the sand varies from 20 to 50 feet.

The Tucker sand lying about 100 feet below the Bartlesville has been recognized near Coodys Bluff and in the northwest parts of the field.

Wells have had initial production as high as 500 barrels, soon settling to a very steady small production. Water is present, but apparently does not constitute a menace. In the developed area, wells are spaced at about 4 acres per well.

ESTIMATED FUTURE PRODUCTION TABLE, NOWATA DISTRICT.

Average Production per Well for Taxable Year.	Estimated Recoverable Underground Reserves per Well.	Average Production per Well for Taxable Year.	Estimated Recoverable Underground Reserves per Well.	Average Production per Well for Taxable Year.	Estimated Recoverable Underground Reserves per Well.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
150	0	700	2,200	2,500	5,300
200	300	800	2,500	3,000	5,800
250	550	900	2,740	3,500	6,180
300	800	1,000	3,000	4,000	6,520
350	1,000	1,250	3,550	4,500	6,820
400	1,220	1,500	4,000	5,000	7,100
450	1,470	1,750	4,370	6,000	7,550
500	1,600	2,000	4,700	7,000	7,880
600	1,900	2,250	5,000	8,000	8,175

Adair Pool, Nowata County, Okla.

The Adair pool is in the east half of townships 25 to 26 north, range 14 east, and in parts of townships 25 and 26 north, range 15 east, all in Nowata County. The producing sand is the Bartlesville, found at an average depth of 1,050 feet. Its thickness varies from 12 to 45 feet, with an average of 30 feet. Discovery and first development in this district was in 1912. Wells drilled in that year had an initial production as high as 400 barrels. The production almost always shows a very sharp decline for the first two years followed by a very slight decline in the settled production through a period of years. Spacing of wells is about 7 acres per well.

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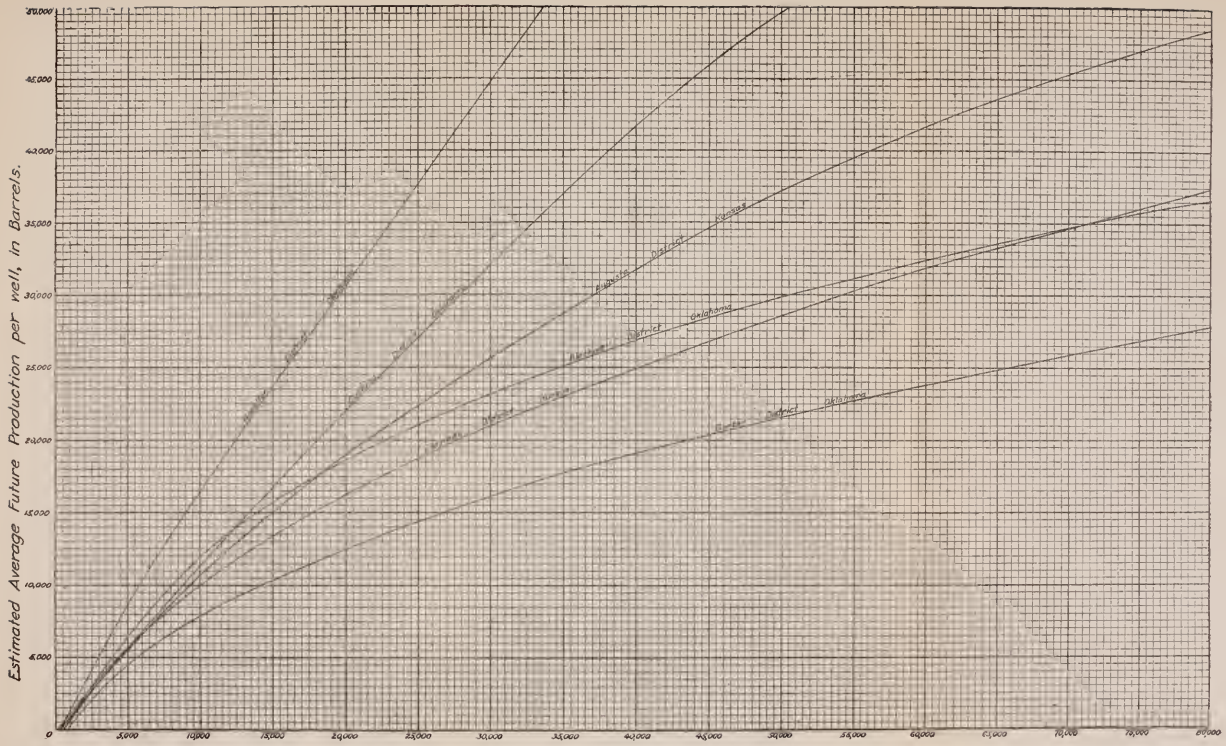


FIG. 7.—ESTIMATED AVERAGE FUTURE PRODUCTION CURVES, PART OF MIDCONTINENT FIELD.

(To face page 124.)

ESTIMATED FUTURE PRODUCTION TABLE, ADAIR DISTRICT.

Average Production per Well for Taxable Year.	Estimated Recoverable Underground Reserves.	Average Production per Well for Taxable Year.	Estimated Recoverable Underground Reserves.	Average Production per Well for Taxable Year.	Estimated Recoverable Underground Reserves.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
100	200	700	1,150	2,500	3,275
150	275	800	1,280	3,000	3,750
200	375	900	1,420	3,500	4,200
250	450	1,000	1,550	4,000	4,650
300	550	1,250	1,850	4,500	5,075
350	620	1,500	2,150	5,000	5,500
400	700	1,750	2,450	6,000	6,325
450	780	2,000	2,750	7,000	7,150
500	850	2,250	3,000	8,000	7,900
600	1,000				

Okesa District, Osage County, Okla.

The curves and tables for this district are compiled from records of the Osage Agency. The district is included in townships 26 and 27 north, ranges 10 and 11 east, and comprises the Okesa pool and other production west of Bartlesville. Development began in 1904 and has proceeded to the present time. The principal producing sand is the Bartlesville, found at depths varying from 1,575 to 1,900 feet, according to location and topography, with an average thickness of 30 feet.

ESTIMATED FUTURE PRODUCTION TABLE—OKESA DISTRICT.

Average Production per Well for Taxable Year.	Estimated Recoverable Underground Reserves.	Average Production per Well for Taxable Year.	Estimated Recoverable Underground Reserves.	Average Production per Well for Taxable Year.	Estimated Recoverable Underground Reserves.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
75	0	600	3,000	2,000	9,050
150	500	700	3,400	2,250	9,800
200	750	800	4,000	2,500	10,600
250	1,000	900	4,450	3,000	11,900
300	1,300	1,000	4,950	3,500	13,075
350	1,800	1,250	6,000	4,000	14,075
400	1,950	1,500	7,100	4,500	15,100
450	2,150	1,750	8,500	5,000	16,000
500	2,440				

ESTIMATED FUTURE PRODUCTION TABLE, ADAIR DISTRICT.

Average Production per Well for Taxable Year.	Estimated Recoverable Underground Reserves.	Average Production per Well for Taxable Year.	Estimated Recoverable Underground Reserves.	Average Production per Well for Taxable Year.	Estimated Recoverable Underground Reserves.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
100	200	700	1,150	2,500	3,275
150	275	800	1,280	3,000	3,750
200	375	900	1,420	3,500	4,200
250	450	1,000	1,550	4,000	4,650
300	550	1,250	1,850	4,500	5,075
350	620	1,500	2,150	5,000	5,500
400	700	1,750	2,450	6,000	6,325
450	780	2,000	2,750	7,000	7,150
500	850	2,250	3,000	8,000	7,900
600	1,000				

Okesa District, Osage County, Okla.

The curves and tables for this district are compiled from records of the Osage Agency. The district is included in townships 26 and 27 north, ranges 10 and 11 east, and comprises the Okesa pool and other production west of Bartlesville. Development began in 1904 and has proceeded to the present time. The principal producing sand is the Bartlesville, found at depths varying from 1,575 to 1,900 feet, according to location and topography, with an average thickness of 30 feet.

ESTIMATED FUTURE PRODUCTION TABLE—OKESA DISTRICT.

Average Production per Well for Taxable Year.	Estimated Recoverable Underground Reserves.	Average Production per Well for Taxable Year.	Estimated Recoverable Underground Reserves.	Average Production per Well for Taxable Year.	Estimated Recoverable Underground Reserves.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
75	0	600	3,000	2,000	9,050
150	500	700	3,400	2,250	9,800
200	750	800	4,000	2,500	10,600
250	1,000	900	4,450	3,000	11,900
300	1,300	1,000	4,950	3,500	13,075
350	1,800	1,250	6,000	4,000	14,075
400	1,950	1,500	7,100	4,500	15,100
450	2,150	1,750	8,500	5,000	16,000
500	2,440				

Avant-Ramona District, Osage and Washington Counties, Okla.

The curves and tables of this district are derived from records of properties in Osage County and eastward into Washington County. The area is located in townships 22–23 and 24 north, ranges 11 and 12 east. The principal producing sands are the Peru, at 800–1,200 feet, and the Bartlesville, at an average depth of 1,620 feet, the latter with an average thickness of about 54 feet.

ESTIMATED FUTURE PRODUCTION TABLE—AVANT-RAMONA DISTRICT.

Average Production per Well for Taxable Year.	Estimated Recoverable Underground Reserves per Well.	Average Production per Well for Taxable Year.	Estimated Recoverable Underground Reserves per Well.	Average Production per Well for Taxable Year.	Estimated Recoverable Underground Reserves per Well.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
100	100	700	2,975	3,000	11,350
150	275	800	3,500	3,500	12,520
200	500	900	4,000	4,000	13,700
250	700	1,000	4,500	4,500	14,725
300	900	1,250	5,625	5,000	15,600
350	1,125	1,500	6,700	6,000	16,915
400	1,350	1,750	7,675	7,000	17,780
450	1,610	2,000	8,500	8,000	18,425
500	1,900	2,250	9,300	9,000	19,000
600	2,410	2,500	10,050	10,000	19,350

Cleveland District, Pawnee County, Okla.

The Cleveland district is in townships 20 and 21 north, ranges 7 and 8 east, all in Pawnee County. No Osage records were used in the compilation, but it is considered that the curve may apply to the extension of the Cleveland pool into Osage County and also to the so-called Olney pool, southwest of Cleveland. Development was begun in 1904, mainly in town-lot drilling in Cleveland. The principal producing sands with their average depth are: Layton, 1,200 to 1,300 feet; Cleveland, 1,650; Skinner, 2,200; Bartlesville, 2,400; and Tucker, 2,600.

Many wells formerly producing from upper sands have been deepened to the last two named, which are the most important producers. Wells come in with high initial capacity and show long life due to the thickness of the Bartlesville sand, which ranges from 30 to 95 feet. Vacuum has been quite widely applied to wells from

1916 to the present time. The spacing is about $6\frac{1}{2}$ acres per well outside of the town drilling.

ESTIMATED FUTURE PRODUCTION TABLE—CLEVELAND DISTRICT.

Average Production per Well for Taxable Year.	Estimated Recoverable Underground Reserves per Year.	Average Production per Well for Taxable Year.	Estimated Recoverable Underground Reserves per Year.	Average Production per Well for Taxable Year.	Estimated Recoverable Underground Reserves per Year.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
500	0	2,500	10,200	11,000	23,375
600	900	3,000	11,500	12,000	24,700
700	1,700	3,500	12,575	13,000	26,050
800	2,500	4,000	13,600	14,000	27,400
900	3,250	4,500	14,400	15,000	28,750
1,000	3,800	5,000	15,200	16,000	30,100
1,250	5,440	6,000	16,650	17,000	31,450
1,500	6,700	7,000	18,100	18,000	32,800
1,750	8,000	8,000	19,400	19,000	34,150
2,000	8,700	9,000	20,700	20,000	35,500
2,250	9,450	10,000	22,050		

Bird Creek District, Tulsa County, Okla.

The curves and tables herewith apply to the area, all of which is in Tulsa County, in townships 20, 21, and 22 north, ranges 12 to

ESTIMATED FUTURE PRODUCTION TABLE—BIRD CREEK-SKIATOOK DISTRICT.

Average Production per Well for Taxable Year.	Estimated Recoverable Underground Reserves per Well.	Average Production per Well for Taxable Year.	Estimated Recoverable Underground Reserves per Well.	Average Production per Well for Taxable Year.	Estimated Recoverable Underground Reserves per Well.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
100	200	700	2,800	2,500	9,400
150	400	800	3,200	3,000	11,200
200	700	900	3,630	3,500	12,800
250	900	1,000	4,050	4,000	14,500
300	1,200	1,250	5,000	4,500	16,100
350	1,300	1,500	5,800	5,000	17,700
400	1,600	1,750	6,800	6,000	20,800
450	1,750	2,000	7,800	7,000	23,900
500	2,000	2,250	8,700	8,000	27,000
600	2,400				

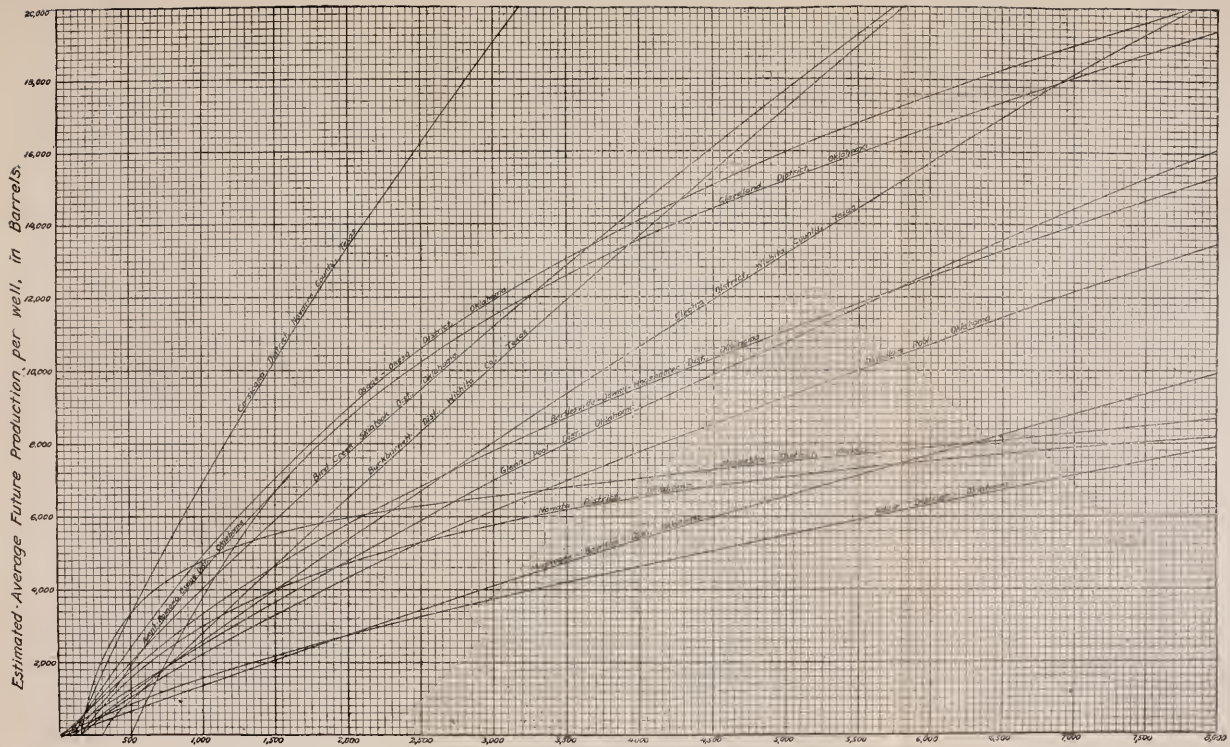
13 east. Included are the North Tulsa, Flat Rock, Turley, Sperry, and Skiatook pools. The producing sands are the Bartlesville, at an average depth of 1,130 feet, with an average thickness of 41 feet, and the Tucker, found at an average depth of 1,290 feet and an average thickness of 28 feet. This is one of the oldest and steadiest producing fields of Oklahoma. Development began in 1906 and has continued to date, with most of the development in 1911 and 1912. Wells were reported with an initial production as high as 400 barrels. The district has shown great lasting qualities. Within the last two years vacuum has been generally applied. There is considerable water trouble in some parts of the district.

Glenn Pool, Creek County, Okla.

The curves and tables for the Glenn field cover townships 16–19 north, ranges 11–13 east. This includes the Glenn, Sapulpa, and Taneha pools, with the northeast and southeast extensions. Several sands are productive in this area, the more important of which are the Red Fork, Glenn, and Squaw or Taneha. Some production has also been obtained from sands above the Red Fork, one between the Red Fork and Glenn, and three below the Taneha sand. Of the three important producing sands, the Red Fork is about 1,100 feet deep and ranges from 10 to 30 feet in thickness.

ESTIMATED FUTURE PRODUCTION TABLE—GLENN POOL DISTRICT.

Average Production per Well for Taxable Year.	Estimated Recoverable Underground Reserves per Well.	Average Production per Well for Taxable Year.	Estimated Recoverable Underground Reserves per Well.	Average Production per Well for Taxable Year.	Estimated Recoverable Underground Reserves per Well.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
150	390	3,500	8,000	38,500	56,300
200	510	7,000	14,500	42,500	60,000
300	840	10,500	20,200	45,500	63,600
400	1,100	14,000	25,600	49,000	67,000
500	1,350	17,500	30,700	52,500	70,150
600	1,600	20,000	34,300	56,000	73,200
700	1,800	21,000	35,000	59,500	76,150
1,050	2,650	24,500	40,200	63,000	79,150
1,750	4,200	28,000	44,300	66,500	82,000
2,800	6,700	31,500	48,500	70,000	84,600
3,150	7,250	35,000	52,600	81,500	92,400



111069°—19.

FIG. 8.—ESTIMATED AVERAGE FUTURE PRODUCTION CURVES, PART OF MIDCONTINENT FIELD.

(To face page 128.)

The Glenn sand averages about 90 feet in thickness and about 1,750 feet below the surface. The Squaw or Taneha sand is about 30 feet thick, and is found at a depth of about 1,900 feet. Of these, the Glenn is the most important, and the Red Fork is second as a producer. Discovery here was in 1906. The structure is monoclinical with a westward dip of about 50 feet per mile. Cross flexures and terraces on this westward dip seem to have had a definite influence on oil accumulation. The average spacing is about 6 acres per well.

Cushing Field, Creek County, Okla.

The curves and tables for the Cushing field cover townships 16, 17, 18, and 19 north, ranges 6 and 7 east. This includes Cushing proper and outlying pools. Discovery was made in 1912 in the Wheeler sand, production being developed later in the Layton, Bartlesville, and Tucker sands. Of the four important sands, the Layton is from 1,200 to 1,500 feet deep, and has an average thickness of about 50 feet. The Wheeler sand averages about 2,000 to 2,100 feet in depth and about 50 feet in thickness. The Bartlesville sand is from 2,500 to 2,700 feet deep and ranges in thickness from 50 to 200 feet. The Tucker sand is about 2,800 feet deep and

ESTIMATED FUTURE PRODUCTION TABLE—CUSHING DISTRICT.

Average Production per Well for Taxable Year.	Estimated Recoverable Underground Reserves.	Average Production per Well for Taxable Year.	Estimated Recoverable Underground Reserves.	Average Production per Well for Taxable Year.	Estimated Recoverable Underground Reserves.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
500	400	7,000	7,900	35,000	37,000
1,000	1,000	8,000	9,000	40,000	41,700
1,500	1,600	9,000	10,100	45,000	45,900
2,000	2,150	10,000	11,200	50,000	49,900
2,500	2,800	12,000	13,400	55,000	53,600
3,000	3,260	14,000	15,600	60,000	57,200
3,500	3,800	16,000	17,800	65,000	60,600
4,000	4,370	18,000	19,800	70,000	64,100
4,500	5,000	20,000	22,000	75,000	67,400
5,000	5,700	25,000	27,000	80,000	70,600
6,000	6,800	30,000	32,000		

The Glenn sand averages about 90 feet in thickness and about 1,750 feet below the surface. The Squaw or Taneha sand is about 30 feet thick, and is found at a depth of about 1,900 feet. Of these, the Glenn is the most important, and the Red Fork is second as a producer. Discovery here was in 1906. The structure is monoclinical with a westward dip of about 50 feet per mile. Cross flexures and terraces on this westward dip seem to have had a definite influence on oil accumulation. The average spacing is about 6 acres per well.

Cushing Field, Creek County, Okla.

The curves and tables for the Cushing field cover townships 16, 17, 18, and 19 north, ranges 6 and 7 east. This includes Cushing proper and outlying pools. Discovery was made in 1912 in the Wheeler sand, production being developed later in the Layton, Bartlesville, and Tucker sands. Of the four important sands, the Layton is from 1,200 to 1,500 feet deep, and has an average thickness of about 50 feet. The Wheeler sand averages about 2,000 to 2,100 feet in depth and about 50 feet in thickness. The Bartlesville sand is from 2,500 to 2,700 feet deep and ranges in thickness from 50 to 200 feet. The Tucker sand is about 2,800 feet deep and

ESTIMATED FUTURE PRODUCTION TABLE—CUSHING DISTRICT.

Average Production per Well for Taxable Year.	Estimated Recoverable Underground Reserves.	Average Production per Well for Taxable Year.	Estimated Recoverable Underground Reserves.	Average Production per Well for Taxable Year.	Estimated Recoverable Underground Reserves.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
500	400	7,000	7,900	35,000	37,000
1,000	1,000	8,000	9,000	40,000	41,700
1,500	1,600	9,000	10,100	45,000	45,900
2,000	2,150	10,000	11,200	50,000	49,900
2,500	2,800	12,000	13,400	55,000	53,600
3,000	3,260	14,000	15,600	60,000	57,200
3,500	3,800	16,000	17,800	65,000	60,600
4,000	4,370	18,000	19,800	70,000	64,100
4,500	5,000	20,000	22,000	75,000	67,400
5,000	5,700	25,000	27,000	80,000	70,600
6,000	6,800	30,000	32,000		

is about 25 feet thick. The Layton is a true sand, gives fair-sized wells that held up fairly well; the Wheeler is a sand and lime formation in which the wells have large initial production but decline rapidly and have short lives; the Bartlesville sand is a true sand and has many pays. It is by far the most important of the four sands and gives very large wells but has developed much water trouble. Because of the four sands, there are often several wells drilled on each location, but the average spacing for each sand is about 7 acres per well.

Muskogee-Boynton District, Muskogee County. Okla.

These fields were combined into one district, since the individual lease records plotted as the same type of curve. Wells are scattered and fields spotted. Sands are variable in thickness and character.

ESTIMATED FUTURE PRODUCTION TABLE—MUSKOGEE-BOYNTON DISTRICT.

Average Production per Well for Taxable Year.	Estimated Recoverable Underground Reserves.	Average Production per Well for Taxable Year.	Estimated Recoverable Underground Reserves.	Average Production per Well for Taxable Year.	Estimated Recoverable Underground Reserves.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
150	150	3,500	4,700	17,000	18,250
300	300	4,000	5,400	18,000	19,100
400	500	4,500	6,000	19,000	19,900
500	650	5,000	6,500	20,000	20,700
600	800	6,000	7,700	22,000	22,200
700	900	7,000	8,800	24,000	23,600
800	1,100	8,000	9,850	26,000	25,200
900	1,200	9,000	10,800	28,000	26,800
1,000	1,400	10,000	11,900	30,000	27,400
1,200	1,700	11,000	12,900	32,000	28,500
1,400	1,950	12,000	13,800	34,000	29,450
1,600	2,250	13,000	14,750	36,000	30,350
1,800	2,500	14,000	15,650	38,000	31,200
2,000	2,750	15,000	16,500	40,000	32,000
2,500	3,400	16,000	17,400	42,000	32,800
3,000	4,100				

Okmulgee Field, Okmulgee County, Okla.

The curves and tables for the Okmulgee field cover townships 12–15 north, and range 12–14 east. This includes several small but distinct areas of production. Several sands are productive in this large area. The zone of production, taking the field as a whole, is from 500 feet to nearly 2,500 feet deep and the sands range from 2 feet to 200 feet thick, but average less than 100 feet. As the sand lenses are notably discontinuous, detailed treatment of the curves of the separate lenses probably would not be justified. Some leases, however, produce oil from three distinct horizons. The thicker sands, in some cases at least, carry salt water in the lower portions, and in this may effect future recoveries. In one well, production may range from 500 feet to 800 feet in depth. More commonly ones and furnishes the oil. Since the sands are lenticular, the area is not uniformly productive. The general structure is a westward dipping monocline, but the subsurface structures are not well indicated at the surface. Unconformable stratigraphic relations seem to be indicated, but textural features and the character of the cement in the sands may be important factors. Discovery of oil was made here about 1907. The average well spacing is about 8 to 10 acres.

ESTIMATED FUTURE PRODUCTION TABLE—OKMULGEE DISTRICT.

Average Production per Well for Taxable Year.	Estimated Recoverable Underground Reserves per Well.	Average Production per Well for Taxable Year.	Estimated Recoverable Underground Reserves per Well.	Average Production per Well for Taxable Year.	Estimated Recoverable Underground Reserves per Well.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
150	150	1,500	3,320	5,000	9,300
200	300	2,000	4,350	5,500	10,000
250	420	2,500	5,330	6,000	10,700
300	550	3,000	6,150	6,500	11,500
350	675	3,500	7,000	7,000	12,150
400	800	4,000	7,800	7,500	12,800
500	1,050	4,500	8,500	8,000	13,500
1,000	2,250				

Garber Pool, Garfield County, Okla.

This is one of the younger pools of Oklahoma, the discovery well being brought in late in 1916. Drilling is somewhat difficult owing to the red-beds strata which overlie the production sands. The field is at present confined to the limits of a domal structure found in townships 21 and 22 north and ranges 3 and 4 west. One oil and one gas sand are found, the gas at about 850 feet and the oil at approximately 1,100 feet.

ESTIMATED FUTURE PRODUCTION TABLE—GARBER DISTRICT.

Average Production per Well for Taxable Year.	Estimated Recoverable Underground Reserves.	Average Production per Well for Taxable Year.	Estimated Recoverable Underground Reserves.	Average Production per Well for Taxable Year.	Estimated Recoverable Underground Reserves.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels	Barrels.
750	0	6,000	5,400	25,000	14,400
1,000	300	7,000	6,100	30,000	16,300
1,500	1,000	8,000	6,800	35,000	17,800
2,000	1,600	9,000	7,400	40,000	19,100
2,500	2,200	10,800	7,900	45,000	20,300
3,000	2,700	12,500	9,300	50,000	21,600
3,500	3,300	15,000	10,300	60,000	23,800
4,000	3,700	17,500	11,400	70,000	25,800
4,500	4,200	20,000	12,500	80,000	27,800
5,000	4,500	22,500	13,400		

Healdton Field, Carter County, Okla.

The curves and tables for the Healdton field cover townships 3 and 4 south, ranges 3 and 4 west. Production here is essentially from two horizons, the so-called Healdton sand, at depths from 800 to 1,200 feet, and the deeper sand in the southeast part of the field between 1,800 and 2,000 feet, which may or may not be the same. One well has production from the Bull Head sand at a depth of about 2,800 feet. The Healdton sand consists of sand lenses from 3 feet to more than 60 feet thick, separated by beds of shale and thin limestone. The deeper sands in the southeast extension have the same characteristics. Some of the wells are producing from the upper sand lenses, other wells are producing only from the lower portion of the Healdton sand, and others are producing

from several or all of the sand lenses penetrated in these places. The general structure is that of a dome with a northwest and a southeast extension, with an alignment parallel to the Arbuckle Mountains. The steepest dip is to the southwest at about 400 feet to the mile, and this edge of production is remarkably sharply outlined. Subsurface structures do not correspond closely with those at the surface, and their interpretation is dependent upon well records. Accumulation seems to have been influenced

ESTIMATED FUTURE PRODUCTION TABLE—HEALDTON DISTRICT.

Average Production per Well for Taxable Year.	Estimated Recoverable Underground Reserves.	Average Production per Well for Taxable Year.	Estimated Recoverable Underground Reserves.	Average Production per Well for Taxable Year.	Estimated Recoverable Underground Reserves.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
250	0	20,000	30,200	65,000	94,300
500	700	25,000	37,700	70,000	101,350
1,000	1,575	30,000	44,600	75,000	108,200
2,000	3,300	35,000	52,000	80,000	115,250
3,000	5,000	40,000	59,000	85,000	122,500
4,000	6,850	45,000	66,000	90,000	129,400
5,000	8,500	50,000	73,000	95,000	136,500
10,000	16,200	55,000	80,000	100,000	143,500
15,000	23,200	60,000	87,150		

ESTIMATED FUTURE PRODUCTION TABLE—BLACKWELL DISTRICT, OKLA.

Average Production per Well for Taxable Year.	Estimated Recoverable Underground Reserves.	Average Production per Well for Taxable Year.	Estimated Recoverable Underground Reserves.	Average Production per Well for Taxable Year.	Estimated Recoverable Underground Reserves.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
500	0	22,500	20,000	90,000	38,400
1,000	1,000	25,000	21,000	100,000	40,000
2,500	3,000	30,000	23,200	125,000	44,100
5,000	6,500	35,000	25,200	150,000	48,500
7,500	9,500	40,000	26,800	175,000	52,600
10,000	12,000	45,000	28,500	200,000	56,800
12,500	14,000	50,000	29,800	250,000	65,200
15,000	16,000	60,000	32,500	300,000	63,800
17,500	17,500	70,000	34,700	350,000	82,200
20,000	18,800	80,000	36,700	400,000	90,700

strongly by texture as well as by structure. The first production was in August, 1913.

The average well spacing is about $2\frac{1}{2}$ acres.

Corsicana Pool, Navarro County, Tex.

The Corsicana pool is the oldest producing field in the State, being now in its twenty-third year. The field is usually divided into two districts, the Corsicana or light-oil pool, which supplies a crude of about 38° Baumé, and the Powell, or heavy-oil district, furnishing oil of about 24° Baumé. The first oil was produced in 1896. The Powell pool was opened in 1900. As production in this district declines water encroaches and a number of properties have been abandoned. The sands which produce the heavy and light oil are in different geological horizons. The heavy-oil sand probably corresponds to the Nacatoch sand of the Caddo field, Louisiana. The light-oil sands occur geologically about 800 feet lower. The Corsicana light-oil sands are found from 900 to 1,200 feet and the Powell sands are found from 650 to 950 feet below the surface. They range in thickness from a few feet up to 60 feet. A comparison of the various properties in the heavy and light oil pools seemed to indicate that the rate of decline was approximately

ESTIMATED FUTURE PRODUCTION TABLE—CORSICANA FIELD.

Average Production per Well for Taxable Year.	Estimated Recoverable Underground Reserves per Well.	Average Production per Well for Taxable Year.	Estimated Recoverable Underground Reserves per Well.	Average Production per Well for Taxable Year.	Estimated Recoverable Underground Reserves per Well.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
100	0	2,400	15,700	4,600	27,800
200	800	2,600	16,800	4,800	28,900
400	2,500	2,800	17,900	5,000	30,000
600	4,100	3,000	19,000	5,200	31,200
800	5,500	3,200	20,100	5,400	32,300
1,000	7,000	3,400	21,300	5,500	32,800
1,200	8,300	3,600	22,400	6,000	35,600
1,400	9,600	3,800	23,400	6,500	38,300
1,600	10,750	4,000	24,500	7,000	41,100
1,800	12,200	4,200	25,600	7,500	43,800
2,000	13,400	4,400	26,700	8,000	46,600
2,200	14,500				

the same in both instances. It was thought advisable, therefore, to consider the district as one pool, and the curve will apply to all the properties in this field.

Electra Pool, Wichita County, Tex.

The Electra pool is located in the western portion of Wichita and the eastern portion of Wilbarger Counties. The pool was opened in 1910 and at the present time its general limits seem fairly well defined. The main pool includes about 9,800 acres of proven territory. The oil is found in overlapping sands at varying depths between 350 and 2,050 feet below the surface. No individual sand has any great lateral extent, though the sands overlap in such manner that production is continuous over the entire area, with no intervening dry spots of any considerable size. Individual sands are seldom more than 25 feet thick, though in a few instances 35 feet or more have been reported. The average thickness of sands in the field will probably be well under 25 feet. The oil produced in this district has a gravity of from 40° to 44° Baumé. The gas pressure has never been strong in wells, even in the early stages of development.

ESTIMATED FUTURE PRODUCTION TABLE—ELECTRA FIELD.

Average Production per Well During Taxable Year.	Estimated Average Future Production of Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production of Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production of Well.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
100	0	2,800	7,500	7,200	18,600
200	400	3,000	8,000	7,600	19,500
400	900	3,200	8,600	8,000	20,400
600	1,600	3,400	9,100	8,400	21,300
800	2,100	3,600	9,600	8,800	22,200
1,000	2,600	3,800	10,200	9,200	23,000
1,200	3,200	4,000	10,700	9,600	23,800
1,400	3,700	4,400	11,700	10,000	24,600
1,600	4,300	4,800	12,700	11,000	26,600
1,800	4,700	5,200	13,700	12,000	28,500
2,000	5,300	5,600	14,700	13,000	30,400
2,200	5,800	6,000	15,700	14,000	32,200
2,400	6,400	6,400	16,700	15,000	33,900
2,600	7,000	6,800	17,700	16,000	35,600

Burkburnett Pool, Wichita County, Tex.

The Burkburnett pool has an east-west axis and includes approximately 10,500 acres of proven territory. The sands are fairly regular but it is often hard and unproductive in spots and relatively open and prolific near by. The bulk of production comes from sands found between 1,000 and 1,800 feet below the surface, with a range in thickness up to 35 feet. In some places a small production is secured from shallow sands found between 350 and 500 feet. The oil has a gravity of 40° to 42° Baumé.

ESTIMATED FUTURE PRODUCTION TABLE—BURKBURNETT FIELD.

Average Production of Well During Taxable Year.	Estimated Average Future Production of Well.	Average Production of Well During Taxable Year.	Estimated Average Future Production of Well.	Average Production of Well During Taxable Year.	Estimated Average Future Production of Well.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
300	0	3,600	12,300	10,000	34,000
400	600	3,800	13,000	11,000	37,100
600	1,300	4,000	13,700	12,000	40,200
800	2,100	4,400	15,000	13,000	43,500
1,000	2,800	4,800	16,500	14,000	46,500
1,200	3,500	5,200	17,800	15,000	49,600
1,400	4,300	5,600	19,300	16,000	52,600
1,600	5,000	6,000	20,600	17,000	55,700
1,800	5,700	6,400	22,000	18,000	58,600
2,000	6,500	6,800	23,300	19,000	61,600
2,200	7,200	7,200	24,800	20,000	64,500
2,400	8,000	7,600	26,000	22,000	70,300
2,600	8,700	8,000	27,400	24,000	76,000
2,800	9,400	8,400	28,700	26,000	81,800
3,000	10,100	8,800	30,000	28,000	88,500
3,200	10,800	9,200	31,300	30,000	93,000
3,400	11,500	9,600	32,800	32,000	98,500

FUTURE PRODUCTION CURVES FOR NORTHERN LOUISIANA FIELDS.

The oil fields covered by this investigation are those in the northern part of the State of Louisiana generally known as the Caddo, the De Soto and the Red River pools. There are other very small producing areas in the district, but they have not sufficient production to furnish data on which to construct curves.

The production area in Marion County, Tex., is also included in this report, as it is merely an extension of the Caddo oil field.

Fairly complete data were procured on about 85 per cent of the properties in the producing area and the curves show the average production per well.

The general geological conditions in these fields are similar. The pay sands occur in very gentle folds and the oil is at first under high gas pressure, and is in close association with bottom water over nearly all the field. This water is an ever-present menace and necessitates great care in drilling as well as in subsequent operations. Wells with large production often go suddenly to water and even with care this is the invariable end of all wells in these fields.

Surface exposures are so irregular and the formations exposed so recent that they give no clue to underground structure.

The main source of the oil is the "Woodbine" sand of Cretaceous age, which is encountered at a depth of from 2,200 to 2,300 feet. Because of the poor samples obtained by the rotary method of drilling, which is universally used here, the well logs generally show oil as coming from shale. As it is always the intent of the driller to merely touch the top of the oil sand, because of the danger of water, the thickness of this "sand" is not definitely known.

The Nacatoch sand at a depth of about 800 feet produces a great deal of gas and some heavy oil. The production from this sand is of minor importance compared to the production from the Woodbine, and the records are such that it is impossible to segregate its production.

The Caddo Oil Field.

For the purpose of estimating future production, this field is divided into four pools. These divisions were made on a basis of decline of production by comparing decline curves over the various areas. Areas where the decline curves were similar were taken to represent a distinct pool and a general curve for this was constructed.

The Mooringsport pool comprises townships 21 north, range 16 west, 20 north, range 16 west, and 20 north, range 15 west. A curve was constructed for each of these townships, and other curves for each of the larger companies whose holdings are scattered through these townships. These curves proved practically

identical after the period of great gushers was past, so all were combined into one general curve.

A separate curve was made for Marion County, Tex., not because it is materially different, but to have a special record from another State.

The Vivian oil field, to the east and south of Vivian, township 16 north, range 22 west, township 15 north, range 22 west, forms another distinct unit for which a curve was constructed.

The Pine Island pool, township 21 north, range 15 west, shows a very high flush production and rapid decline. The oil is of low gravity, 27° Baumé, and comes from the Woodbine sand under high gas pressure. No accurate estimate of future production can be made on the average production of a well during one year, because the field is so new that the records extend back only 15 months and the decline is so rapid that wells giving as high as 600 barrels a day are exhausted within a year. For this field a curve was made from which the future production can be estimated, if the production for a month is known. To determine the estimated reserve per well, apply the production for the last month of the taxable year to the curve and read off the estimated future production.

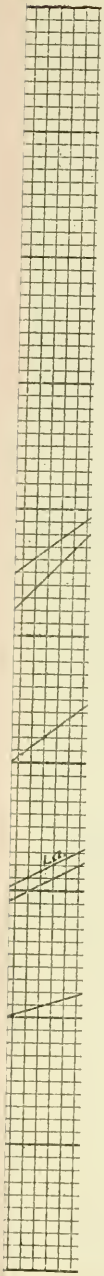
In parts of the Caddo field large areas contain very few dry holes and undrilled ground bounded on four sides by production can reasonably be assumed to be proven territory.

The De Soto and Red River Fields.

The De Soto oil field is located in De Soto Parish, La., in the southeastern part of township 13 north, range 12 west, and the northeastern part of township 12 north, range 13 west, and extends a little into the township to the west.

The Red River oil field is located in Red River Parish, township 13 north, range 10 west, and township 13 north, range 11 west. Production is "spotted" and dry holes are frequent near large producing wells; in the Red River district the sands are slightly more uniformly productive, but the decline is more rapid than in the De Soto field. No undrilled ground can reasonably be called proven here.

The producing sand here is probably the same as the Woodbine in the Caddo field and occurs at a depth of 2,100 to 2,300 feet. The gravity of the oil varies from 38° Baumé to 45.7°



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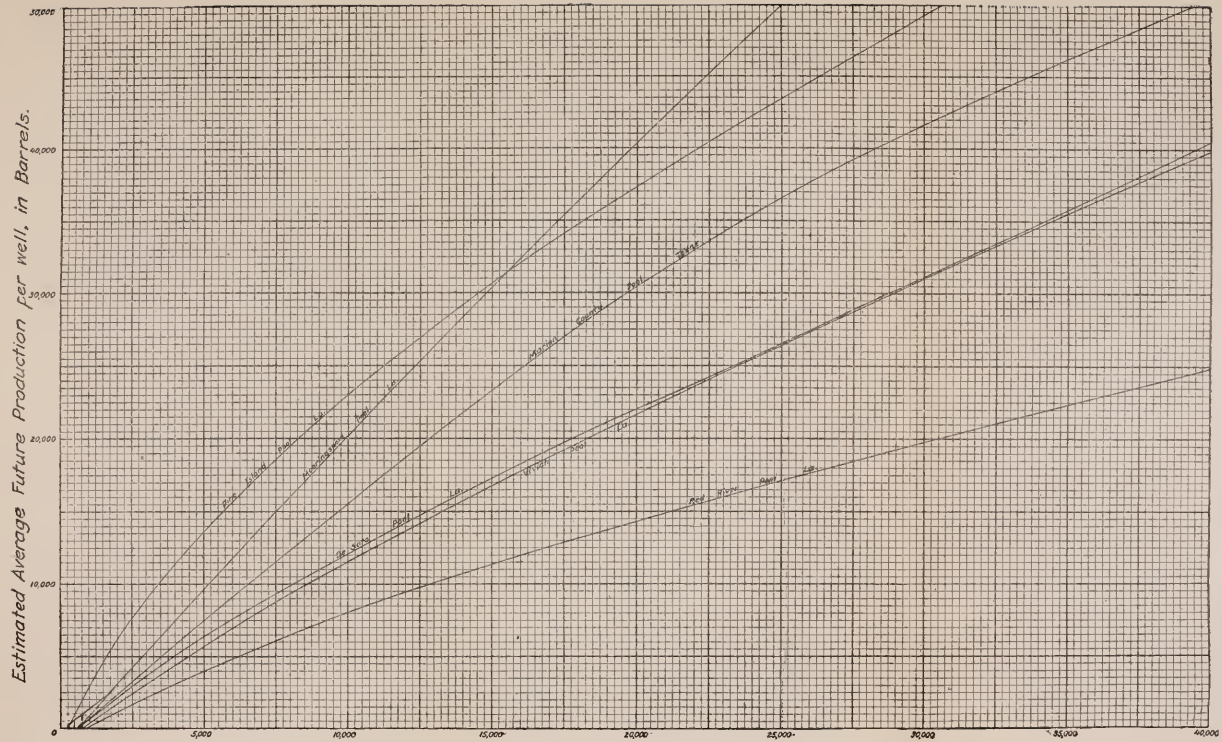

FIG. 9.—ESTIMATED AVERAGE FUTURE PRODUCTION CURVES, NORTHWESTERN LOUISIANA.

Note.—Pine Island curve is for last month's production instead of annual production. See text.

(To face page 138.)

ESTIMATED FUTURE PRODUCTION TABLE.

Mooringsport Pool, Caddo Parish, La.

Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
700	0	3,250	5,800	12,500	25,300
1,000	900	3,500	6,200	15,000	30,300
1,250	1,200	3,750	7,000	17,500	35,400
1,500	2,000	4,000	7,500	20,000	40,300
1,750	2,500	4,250	8,000	22,500	45,200
2,000	3,100	4,500	8,600	25,000	50,000
2,250	3,300	4,750	9,200	30,000	58,500
2,500	4,100	5,000	9,700	35,000	65,500
2,750	4,800	7,500	15,000	40,000	71,200
3,000	5,200	10,000	20,200		

Marion County, Tex.

1,000	700	4,500	6,600	9,500	14,600
1,250	1,200	5,000	7,400	10,000	15,300
1,500	1,500	5,500	8,300	12,250	19,300
1,750	1,900	6,000	9,000	15,000	23,200
2,000	2,400	6,500	9,800	17,250	27,000
2,250	2,800	7,000	10,600	20,000	30,400
2,500	3,300	7,500	11,400	25,000	36,500
3,000	4,100	8,000	12,200	30,000	41,600
3,500	4,900	8,500	13,000	35,000	46,300
4,000	5,800	9,000	13,800	40,000	50,500

Vivian Pool, Caddo Parish, La.

750	0	3,500	3,800	8,000	9,300
1,000	400	4,000	4,400	9,000	10,400
1,250	800	4,500	5,100	10,000	11,500
1,500	1,100	5,000	5,700	15,000	16,700
1,750	1,400	5,500	6,300	20,000	12,600
2,000	1,750	6,000	7,000	25,000	26,400
2,250	2,100	6,500	7,500	30,000	31,000
2,500	2,400	7,000	8,200	35,000	35,500
3,000	3,100	7,500	8,750	40,000	40,000

ESTIMATED FUTURE PRODUCTION TABLE.

Mooringsport Pool, Caddo Parish, La.

Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
700	0	3,250	5,800	12,500	25,300
1,000	900	3,500	6,200	15,000	30,300
1,250	1,200	3,750	7,000	17,500	35,400
1,500	2,000	4,000	7,500	20,000	40,300
1,750	2,500	4,250	8,000	22,500	45,200
2,000	3,100	4,500	8,600	25,000	50,000
2,250	3,300	4,750	9,200	30,000	58,500
2,500	4,100	5,000	9,700	35,000	65,500
2,750	4,800	7,500	15,000	40,000	71,200
3,000	5,200	10,000	20,200		

Marion County, Tex.

1,000	700	4,500	6,600	9,500	14,600
1,250	1,200	5,000	7,400	10,000	15,300
1,500	1,500	5,500	8,300	12,250	19,300
1,750	1,900	6,000	9,000	15,000	23,200
2,000	2,400	6,500	9,800	17,250	27,000
2,250	2,800	7,000	10,600	20,000	30,400
2,500	3,300	7,500	11,400	25,000	36,500
3,000	4,100	8,000	12,200	30,000	41,600
3,500	4,900	8,500	13,000	35,000	46,300
4,000	5,800	9,000	13,800	40,000	50,500

Vivian Pool, Caddo Parish, La.

750	0	3,500	3,800	8,000	9,300
1,000	400	4,000	4,400	9,000	10,400
1,250	800	4,500	5,100	10,000	11,500
1,500	1,100	5,000	5,700	15,000	16,700
1,750	1,400	5,500	6,300	20,000	12,600
2,000	1,750	6,000	7,000	25,000	26,400
2,250	2,100	6,500	7,500	30,000	31,000
2,500	2,400	7,000	8,200	35,000	35,500
3,000	3,100	7,500	8,750	40,000	40,000

ESTIMATED FUTURE PRODUCTION TABLE—*Continued.*

PINE ISLAND POOL, CADDO PARISH, LA.*

Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
100	0	5,000	13,600	20,000	37,300
500	1,100	7,500	18,600	22,500	40,500
1,000	3,000	10,000	23,000	25,000	43,400
2,000	6,300	12,500	27,000	27,500	46,400
3,000	9,000	15,000	30,700	30,000	49,300
4,000	11,500	17,500	34,000		

DE SOTO FIELD, DE SOTO PARISH, LA.

700	0	4,500	5,800	15,000	17,300
1,000	700	5,000	6,400	17,500	19,800
1,500	1,500	6,000	7,500	20,000	22,000
2,000	2,400	7,000	8,700	22,500	24,200
2,500	3,000	8,000	9,800	25,000	26,500
3,000	3,800	9,000	11,100	30,000	31,200
3,500	4,500	10,000	12,200	35,000	38,200
4,000	5,100	12,500	14,700	40,000	40,500

RED RIVER FIELD, RED RIVER PARISH, LA.

900	0	10,000	8,100	27,500	18,400
1,000	200	12,500	9,800	30,000	19,800
2,250	350	15,000	11,300	32,500	21,100
1,500	750	17,500	12,800	35,000	22,300
2,500	3,200	20,000	14,250	37,500	23,700
5,000	4,000	22,500	15,800	40,000	24,900
7,500	6,100	25,000	17,100		

* Average production per well in Pine Island table is for last month of taxable year. See text, p. 138.

FUTURE PRODUCTION CURVES FOR THE ROCKY MOUNTAIN FIELDS.

The region covered in this investigation comprises the Rocky Mountain district, of which Wyoming, Colorado, and Montana, given in the order of their importance, constitute the most valuable part from an oil-producing standpoint. Furthermore, of these three States, Wyoming is by far the most important, producing over 90 per cent of the oil.

The method of attack consisted of the collection, study, classification, and reduction to estimated reserve curves of all average production data from the various oil fields throughout the territory under consideration.

The geologic range of oil-bearing formations in the Rocky Mountain region extends from the middle of the upper Cretaceous down to the base of the Pennsylvanian, or the top of the Madison or Mississippi limestone. The rocks comprising these formations consist mainly of sandstones and shales with a very small percentage of limestone. Throughout the stratigraphic range given above oil-bearing sandstones occur at many different horizons, but the most prolific is the Frontier sandstone series, or Wall Creek sandstones of the Colorado formation. The prevailing type of geologic structure is an elongated asymmetric anticline of more or less regular outline with dips ranging from 10 to 60 or more degrees, the steeper dips generally occurring on the mountainward side.

The producing oil fields in Wyoming occur around the outer margins of the larger structural basins, such as Powder River Basin lying between the Big Horn Mountains and the Black Hills, the Big Horn Basin inclosed by the Big Horn, Owl Creek, and Shoshone Mountains, the Wind River Basin bounded by the Owl Creek, Wind River, and Sweet Grass Mountains, and the Laramie-Rawlins Basin bordered by the Laramie, Medicine Bow, and Rawlins uplifts.

The fields of economic importance occurring within these larger structural basins are Salt Creek, Saddle Rock, Big Muddy, and Buck Creek in the Powder River Basin; Grass Creek, Elk Basin, and Warm Springs in the Big Horn Basin; Pilot Butte and Hudson in the Wind River Basin; and Rock Creek, Lost Soldier, and Ferris in the Laramie-Rawlins Basin. In addition to these, several smaller pools are found; also some new localities which may prove

ultimately of commercial value. In Colorado the two fields are Florence, located in the Arkansas embayment, a large structural province, occurring in the front range of the Rocky Mountains along the Arkansas River Valley, and the Boulder oil field, now practically abandoned, which is situated at the base of the Rocky Mountain uplift in north central Colorado. The Florence and Boulder fields are nearly exhausted at the present time.

In the Rocky Mountain region there were only four fields where sufficient data were available to construct average decline curves on which to base estimates of reserves. In some localities the records were too incomplete to obtain the necessary production data for deriving decline curves, while other promising fields recently discovered were too new to afford the required information for estimating their reserves.

With the exception of Florence, the time during which the fields have been producing is comparatively short, none of the wells having reached the point of exhaustion. Indirectly there are a number of other factors which vary in the different fields, such as character of structure, well spacing, gravity of oil, thickness and porosity of sand, etc., which should be taken into account, as they more or less influence the resulting curve of the field. Under separate headings a brief description is given of the essential conditions as found in each field.

The Florence oil field is the only field in the Rocky Mountain district now producing where the wells have in part reached a point below the economic minimum of production and been abandoned. The first well was drilled here in 1876, and while the production from this locality was never large the life of the wells and low operating expense have permitted its continuous operation much beyond the time that would ordinarily be expected. Several hundred wells have been abandoned in this region. The structure of the field is monoclinal with dips in the productive area of 3° to 6°. There is no oil-bearing sandstone and the oil does not follow any definite horizon or series of beds. It is found in joints, fissures, and along major and minor fault planes. The oil has a gravity of 30.7° Baumé, and as this is a crevice field with the oil segregated into faulted zones any general systematic spacing of wells over the entire field is prevented. Along these faulted lines wells are placed about 600 feet apart.

Four types of decline curves were found to exist in the Florence

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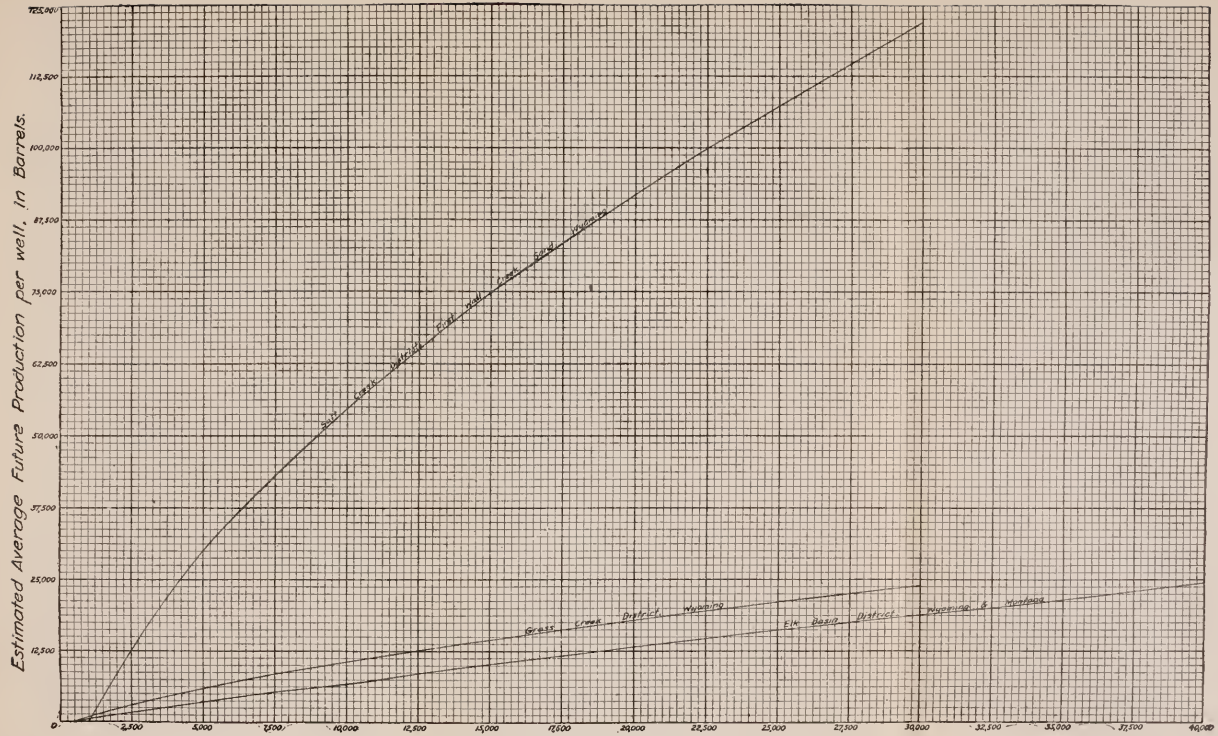

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FIG. 10.—ESTIMATED AVERAGE FUTURE PRODUCTION CURVES, ROCKY MOUNTAIN FIELD.

(To face page 143.)

field. These types did not appear to confine themselves to any particular part of the field, nor did the types seem to be a function of the depth. From this it would appear that these types may possibly be related to the size and extent of the crevice or fissure penetrated by the well. It has, therefore, been impossible to give an average future production curve for the Florence field.

Operating methods employed in the Big Muddy field to date, together with the short period of its production, prevented the construction of a generalized decline curve for this field. The shallow and deep production has been run into the same receiving tanks. Well records are often incomplete and the first oil was piped from the field as late as June, 1917, the first wells having been drilled in 1916. The oil is 34° gravity Baumé and well spacing varies from $4\frac{1}{2}$ to $6\frac{1}{2}$ acres per well. The first and second productive sands locally designated as Shannon are reached at 244 to 415 and 985 to 1,100 feet, respectively. The first Wall Creek occurs at a depth of 2,135 to 3,325 feet. The sands are similar in physical character to those in the Salt Creek field.

Salt Creek Field, Natrona county, Wyo.

This is the most important field in the Rocky Mountain region, and the curve obtained checks out very well with the actual field results to date. The Salt Creek field proper is an elongated dome of the asymmetric type. The structure narrows and plunges slightly to the north and widens and flattens to the southeast. In this field the gravity of the oil is 37° Baumé, and the well spacing is 4.4 acres per well. The depth to the top of the first Wall Creek sandstone varies from 950 to 3,000 feet, depending on the position of the well on the structure. From the well records this sandstone appears to be 125 feet thick. The interval from the base of this structure to the top of the Dakota is about 1,300 feet, and in this stratigraphic range there are six distinct lower sandstone horizons which vary from 10 to 65 feet in thickness, only one of which, the first Wall Creek, has been proven productive thus far. The physical character of the sands in Salt Creek is very favorable and no water-bearing horizons are encountered above the oil; therefore, operating conditions may be regarded as favorable.

field. These types did not appear to confine themselves to any particular part of the field, nor did the types seem to be a function of the depth. From this it would appear that these types may possibly be related to the size and extent of the crevice or fissure penetrated by the well. It has, therefore, been impossible to give an average future production curve for the Florence field.

Operating methods employed in the Big Muddy field to date, together with the short period of its production, prevented the construction of a generalized decline curve for this field. The shallow and deep production has been run into the same receiving tanks. Well records are often incomplete and the first oil was piped from the field as late as June, 1917, the first wells having been drilled in 1916. The oil is 34° gravity Baumé and well spacing varies from $4\frac{1}{2}$ to $6\frac{1}{2}$ acres per well. The first and second productive sands locally designated as Shannon are reached at 244 to 415 and 985 to 1,100 feet, respectively. The first Wall Creek occurs at a depth of 2,135 to 3,325 feet. The sands are similar in physical character to those in the Salt Creek field.

Salt Creek Field, Natrona county, Wyo.

This is the most important field in the Rocky Mountain region, and the curve obtained checks out very well with the actual field results to date. The Salt Creek field proper is an elongated dome of the asymmetric type. The structure narrows and plunges slightly to the north and widens and flattens to the southeast. In this field the gravity of the oil is 37° Baumé, and the well spacing is 4.4 acres per well. The depth to the top of the first Wall Creek sandstone varies from 950 to 3,000 feet, depending on the position of the well on the structure. From the well records this sandstone appears to be 125 feet thick. The interval from the base of this structure to the top of the Dakota is about 1,300 feet, and in this stratigraphic range there are six distinct lower sandstone horizons which vary from 10 to 65 feet in thickness, only one of which, the first Wall Creek, has been proven productive thus far. The physical character of the sands in Salt Creek is very favorable and no water-bearing horizons are encountered above the oil; therefore, operating conditions may be regarded as favorable.

ESTIMATED FUTURE PRODUCTION TABLE—SALT CREEK FIELD, FIRST WALL CREEK SAND.

Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
1,000	0	55,000	184,000	110,000	289,000
5,000	30,000	60,000	195,000	115,000	297,000
10,000	54,000	65,000	205,000	120,000	305,000
15,000	74,000	70,000	215,000	125,000	313,000
20,000	91,000	75,000	225,000	130,000	321,000
25,000	107,000	80,000	234,000	135,000	329,000
30,000	122,000	85,000	244,000	140,000	337,000
35,000	136,000	90,000	253,000	145,000	344,000
40,000	148,000	95,000	262,000	150,000	351,000
45,000	160,000	100,000	271,000	155,000	358,000
50,000	172,000	105,000	280,000	160,000	365,000

Grass Creek Field, Hot Springs County, Wyo.

The Frontier formation which comprises the Wall Creek sandstone is not exposed on this structure, but erosion has progressed sufficiently to bring the topmost sandstone member of the formation within 340 feet of the surface on the crest of the anticline.

ESTIMATED FUTURE PRODUCTION TABLE—GRASS CREEK FIELD.

Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
600	0	11,000	11,400	22,000	19,200
1,000	790	12,000	12,200	23,000	19,800
2,000	2,360	13,000	12,950	24,000	20,400
3,000	3,670	14,000	13,700	25,000	21,000
4,000	4,870	15,000	14,450	26,000	21,600
5,000	6,000	16,000	15,200	27,000	22,200
6,000	7,000	17,000	15,900	28,000	22,800
7,000	7,950	18,000	16,600	29,000	23,350
8,000	8,850	19,000	17,250	30,000	23,900
9,000	9,750	20,000	17,900	31,000	24,500
10,000	10,600	21,000	18,550	32,000	25,100

This sandstone is water bearing, but the three remaining sandstones of this series are productive and occur at depths ranging from 560 to 1,600 feet. The wells in this field are not cased so that the individual sands are allowed to produce separately, therefore, the curves represent the estimated reserves in the three sands combined.

In working up these data it was found necessary to make use of the monthly production records, and as these represented pipeline runs moving averages were used in order to obtain figures which more nearly represented the actual production for any given month. The results obtained fully justify this procedure. In this field the first wells were drilled in 1914 and the oil run through the pipe line in August, 1915. The spacing in this field is 4.4 acres per well and the gravity of thick 42° Baumé.

Elk Basin Field, Park County, Wyo.

This field is very similar to Grass Creek, and the same methods were used in working up curves, these being based on production by months and moving averages. The gravity of the oil is 42° Baumé, and the spacing of the wells 4.4 acres per well. Generally

ESTIMATED FUTURE PRODUCTION TABLE—ELK BASIN FIELD.

Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
500	0	28,000	17,900	56,000	32,300
2,000	1,300	30,000	19,000	58,000	33,300
4,000	2,850	32,000	20,100	60,000	34,300
6,000	4,350	34,000	21,150	62,000	35,300
8,000	5,750	36,000	22,200	64,000	36,200
10,000	7,100	38,000	23,250	66,000	37,200
12,000	8,400	40,000	24,300	68,000	38,100
14,000	9,700	42,000	25,350	70,000	39,100
16,000	10,900	44,000	27,400	72,000	40,000
18,000	11,100	46,000	26,400	74,000	41,000
20,000	13,300	48,000	28,400	76,000	41,900
22,000	14,500	50,000	29,400	78,000	42,900
24,000	15,700	52,000	30,400	80,000	43,800
26,000	16,800	54,000	31,400		

speaking, the operating conditions are favorable. The structure is an elongated comparatively sharp crested anticline, which is highly dissected by dip faults. These conditions give rise to some irregularities in the outline of the oil-bearing territory on the structure, but thus far appears not to have materially affected the production of individual wells located directly on the faults. The first wells were drilled in 1915 and the oil runs through the pipe line began June, 1916.

FUTURE PRODUCTION CURVES FOR THE CLAIFORNIA OIL FIELDS.

The California oil fields may be roughly divided into two provinces, the first province occupying both sides of the San Joaquin Valley and commonly known as the Valley fields, and the second occupying a large coastal area and commonly known as the Coastal fields. The Valley fields, with one exception, lie on the west side of the San Joaquin Valley and produce the bulk of their oil from the porous Tertiary sandstones, which have been folded into arches and troughs—anticlines and synclines. Although the prevailing type of structure controlling the oil accumulation is relatively sharply folded anticlines, considerable oil has been produced from omnoclines and synclines. The conditions in the Coastal fields are similar in many respects to those of the Valley fields, although a much greater variety of structure is present.

The bulk of the oil produced in California comes from formations of Tertiary age, the proportion coming from the older underlying Cretaceous formations being practically negligible. The principal rocks comprising the oil-bearing series are interbedded sandstones and shales, the oil probably originating in the organic diatomaceous shales and later being accumulated in pools in the overlying or underlying porous sandstones. Throughout a long stratigraphic range of these Tertiary rocks, the oil-bearing sandstones occur, those in one field at one horizon, whereas those in a near-by field may be encountered at an entirely different horizon.

The California fields are usually large and the factors affecting production are rather variable—sometimes even in the same area. For this reason, in preparing curves showing the average future production of wells of varying size, it was necessary to divide some of the larger fields into individual productive units, each unit

including all the wells or properties producing under similar conditions.

Furthermore, many of the California fields are underlain by more than one productive oil zone, and it was necessary to prepare curves showing the average future production of wells that produced from each of these zones. In the following presentation of the curves, the area for which each curve is designed is described, and the zone from which the wells produce, that serve as a basis for the curve, is stated.

Occasionally zone A, in one part of a large field like the Midway field may be geologically equivalent to zone B in another part of the field. No attempt has been made to correlate these zones from one area to another, as none of the curves applies to wells producing from a single zone in different areas.

Because of the lack of data, average future production curves could not be drawn for all producing areas. Only the larger areas are covered. Estimates of the average future production of wells in these areas made by using the curves should be made with caution and with knowledge of the fact that the curves represent *average* conditions, although all the curves presented have been carefully checked by selecting properties at random and making estimates of their future production by the use of curves.

It should be noted that practically all the curves are based on the records of individual wells, only a few having been prepared from the tract production records. For this reason, estimates of the future production of tracts can best be made by using the former curve for estimating the future production of individual wells, and then totaling the estimates of the separate wells. In case a curve has been prepared from records of tract production, an estimate of the future production of any tract in the area may be obtained by determining the average production per well during the last year, determining the future of a well of this size from the curve and then multiplying this estimate by the number of wells. It is true that the future production of an average well on a tract may be made from a curve based on the production records of individual wells. The practice is not recommended, however, because of the greater possibility of error. Much closer estimates may be made if the curves based on the individual wells are used only for making estimates of the average future production of individual wells.

The following examples of procedure in making estimates under certain conditions may be of use:

Case I.—In case a producer desires to estimate the future production of a tract completely drilled on which the production is gradually declining, it is unnecessary to use the average future production curve for the district in which the property is situated. Very likely a much closer estimate can be made by plotting the annual production of the property and by projecting its curve as shown in Fig. 2 of the paper on " Methods of estimating recoverable underground reserves " in another part of this manual.

Case II.—If a property is so nearly drilled up that drainage has materially affected the probable initial production of the undrilled wells on the proved acreage, a curve showing the average annual production per well may be plotted and projected to the estimated economic minimum. The production for any future year may be estimated by multiplying the reading on the projected curve for that year by the number of wells to be producing. In this manner the undrilled wells are considered. This method *can not* be used unless drainage, within all likelihood, has affected the oil reserves under the undrilled territory.

Case III.—A variation of the above method is to estimate the future production of the drilled wells as in Case I or II and determine the ultimate production per acre for the drilled part of the tract and to apply these determined values per acre, with the proper modifications, to the undrilled portion of the tract that is practically certain to produce oil.

Case IV.—Still another method is as follows: Proceed as in the first part of Case III. Then estimate the first year's production of the undrilled wells, preferably by using as a basis of estimate the first year's production of the drilled wells. Determine the future of wells of this size by using the average future production curve. The future production of the proved undrilled land will be the sum of the estimated first year's production and the estimated production thereafter.

The Midway-Sunset Field.

The Midway-Sunset field is so large and producing oil under such diverse conditions that it has been necessary for the present work to divide it into several separate areas, each area containing

the wells that produce oil under practically equivalent conditions. In some parts of the field three zones are productive.

One very marked feature in the underground geologic conditions is the wedging out of the older or basal beds of the Etchegoin formation, along the plane of unconformity between the base of the McKittrick formation and the top of the Maricopa (Monterey) shale. This wedging out causes a decrease in thickness of the productive zone, or the entire elimination of the lower zone toward the outcrop to the west. The wells southwest of the line where these zones combine produce under different conditions from those northeast of that line. For that reason, the area west, southwest, and south of the Buena Vista Hills have been divided into three separate areas, and an average future production curve prepared for each area. There are four areas considered therefore in the Midway-Sunset field:

1. The Fellows Area.
2. The Twenty-five Hill Area.
3. The Maricopa Flat Area.
4. The Buena Vista Hills Area.

It is true that these areas do not include all the wells in the Midway-Sunset field, but the scattered wells outside these areas do not provide sufficiently trustworthy and plentiful records upon which to base curves.

Fellows Area, Midway Field, California.

This area includes most of the wells producing from the thick sand caused by the coalescence of the two zones found to the east. The area may be roughly defined as including all those wells southwest of a line drawn as follows: Beginning at the northwest corner of section 26, township 3 south, range 22 east, proceed southeast to the southeast corner of the same section, thence to a point $\frac{1}{2}$ mile north of the southeast corner section 36, township 31 south, range 22 east, and thence southeast to a point $\frac{1}{4}$ mile north of the center of the south line of section 5, township 32 south, range 23 east, where the area terminates.

The curve was prepared from the individual records of most of the wells in this area.

ESTIMATED FUTURE PRODUCTION TABLE—FELLOWS AREA OF THE MIDWAY FILED.

Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
1,000	0	27,000	73,500	64,000	157,500
2,000	3,000	28,000	76,000	66,000	161,500
3,000	6,000	29,000	78,500	68,000	165,500
4,000	9,000	30,000	81,000	70,000	169,500
5,000	12,000	31,000	83,500	72,000	172,500
6,000	15,000	32,000	86,000	74,000	176,000
7,000	18,000	33,000	88,500	76,000	179,500
8,000	21,000	34,000	91,000	78,000	183,000
9,000	24,000	35,000	93,500	80,000	186,500
10,000	27,000	36,000	96,000	85,000	195,000
11,000	30,000	37,000	98,500	90,000	203,500
12,000	33,000	38,000	101,000	95,000	212,000
13,000	36,000	39,000	103,500	100,000	220,500
14,000	39,000	40,000	106,000	105,000	229,000
15,000	42,000	42,000	111,000	110,000	237,500
16,000	45,000	44,000	115,500	115,000	246,000
17,000	48,000	46,000	120,000	120,000	254,000
18,000	51,000	48,000	124,500	125,000	262,000
19,000	53,500	50,000	129,000	130,000	270,000
20,000	56,000	52,000	133,500	135,000	277,500
21,000	58,500	54,000	137,500	140,000	285,000
22,000	61,000	56,000	141,500	145,000	292,500
23,000	63,500	58,000	145,500	150,000	300,000
24,000	66,000	60,000	149,500	155,000	307,500
25,000	68,500	62,000	153,500	160,000	315,000
26,000	71,000				

Twenty-five Hill Area, Midway Field, California.

This area lies southeast of the Fellows Area and includes all wells lying southwest of a line extending southeastward from a point $\frac{1}{4}$ mile south of the center of section 5, township 32 south, range 23 east, to the center of the south line of section 15, township 32 south, range 23 east, thence to the center of the east line of section 23, township 32 south, range 23 east, and thence to the

center of the south line of section 30, township 32 south, range 24 east. All wells in section 15, township 31, south, range 22 east, and those producing from the first zone only in sections 14 and 23, township 31 south, range 22 east, are also included in this area, and estimates of the future production of these wells may be made by using the same curve.

ESTIMATED FUTURE PRODUCTION TABLE—TWENTY-FIVE HILL AREA.

Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
1,000	0	7,500	43,700	21,000	80,900
1,250	2,800	8,000	45,800	22,000	83,000
1,500	5,400	8,500	47,700	23,000	85,100
1,750	7,900	9,000	49,500	24,000	87,100
2,000	10,300	9,500	51,200	25,000	89,100
2,250	12,600	10,000	52,900	26,000	91,000
2,500	14,700	10,500	54,600	27,000	93,100
2,750	16,700	11,000	56,200	28,000	95,100
3,000	18,600	11,500	57,700	29,000	97,100
3,250	20,400	12,000	59,200	30,000	99,100
3,500	22,200	12,500	60,700	31,000	101,100
3,750	23,900	13,000	62,100	32,000	103,100
4,000	25,600	13,500	63,400	33,000	105,100
4,250	27,200	14,000	64,700	34,000	107,100
4,500	28,800	14,500	66,000	35,000	109,100
4,750	30,300	15,000	67,300	36,000	111,100
5,000	31,700	16,000	69,800	37,000	113,100
5,500	34,300	17,000	72,200	38,000	115,100
6,000	36,800	18,000	74,500	39,000	117,100
6,500	39,200	19,000	76,700	40,000	119,000
7,000	41,500	20,000	78,800		

Maricopa Flat Area.

The curve for this area was prepared from the records of individual wells that produce from the first zone only in the area known as the Maricopa Flat in the Sunset field. The curve should be used for estimating the future production of individual wells at

present producing from this zone and for making similar estimates of other wells drilled to this zone.

FUTURE PRODUCTION TABLE FOR A PORTION OF THE SUNSET OIL FILED, CALIFORNIA, MARICOPA FLAT AREAS.

Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
1,000	0	15,000	62,900	28,000	94,600
2,000	7,800	16,000	65,700	29,000	96,800
3,000	14,500	17,000	68,400	30,000	99,000
4,000	20,500	18,000	71,100	31,000	101,200
5,000	26,000	19,000	73,700	32,000	103,400
6,000	31,000	20,000	76,200	33,000	105,600
7,000	35,600	21,000	78,500	34,000	107,800
8,000	40,000	22,000	80,900	35,000	110,000
9,000	44,000	23,000	83,200	36,000	112,100
10,000	47,700	24,000	85,500	37,000	114,200
11,000	51,000	25,000	87,800	38,000	116,200
12,000	54,100	26,000	90,100	39,000	118,200
13,000	57,100	27,000	92,400	40,000	120,200
14,000	60,000				

Buena Vista Hills Area, Midway Field, Calif.

This curve was prepared from the records of individual wells drilled on practically drilled-up tracts in the Buena Vista Hills. The only records omitted in making the curve were the records of such wells as those belonging to the Honolulu Consolidated Oil Co. in section 6, township 32 south, range 24 east, which have large drainage areas with no, or very little interference, thus causing the wells to decline slowly.

Practically all the wells in this area were treated as if they were producing from one thick zone, for in nearly all parts of the area where a division can be made, the wells now produce without water from both.

ESTIMATED FUTURE PRODUCTION TABLE—BUENA VISTA HILLS.

Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
2,000	0	72,000	166,000	195,000	291,000
4,000	9,000	76,000	171,000	200,000	296,000
6,000	17,000	80,000	176,000	205,000	300,000
8,000	24,000	84,000	181,000	210,000	305,000
10,000	32,000	88,000	185,000	215,000	310,000
12,000	39,000	92,000	189,000	220,000	314,000
14,000	45,000	96,000	194,000	225,000	319,000
16,000	52,000	100,000	198,000	230,000	324,000
18,000	58,000	105,000	203,000	235,000	329,000
20,000	65,000	110,000	208,000	240,000	334,000
22,000	71,000	115,000	214,000	245,000	338,000
24,000	76,000	120,000	218,000	250,000	343,000
26,000	82,000	125,000	224,000	255,000	348,000
28,000	87,000	130,000	229,000	260,000	353,000
30,000	93,000	135,000	234,000	265,000	357,000
32,000	98,000	140,000	239,000	270,000	362,000
34,000	102,000	145,000	243,000	275,000	367,000
36,000	106,000	150,000	248,000	280,000	372,000
38,000	111,000	155,000	253,000	285,000	377,000
40,000	115,000	160,000	258,000	290,000	381,000
44,000	123,000	165,000	265,000	295,000	386,000
48,000	130,000	170,000	267,000	300,000	391,000
52,000	137,000	175,000	272,000	305,000	396,000
56,000	144,000	180,000	277,000	310,000	401,000
60,000	150,000	185,000	282,000	315,000	405,000
64,000	156,000	190,000	286,000	320,000	410,000
68,000	161,000				

McKittrick Field, Kern County, Calif.

The McKittrick field has been very productive, but on account of complex structure, which causes the wells to produce different amounts at different rates, there is a considerable range in productivity. The curve shown was prepared from the production records of many different tracts in this field. Estimates made by

the use of this curve should show within a small percentage of error the amount that actually will be produced.

ESTIMATED FUTURE PRODUCTION TABLE—McKITTRICK FIELD.

Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
1,000	0	10,000	85,000	28,000	177,000
1,500	6,000	11,000	92,000	29,000	181,000
2,000	12,000	12,000	99,000	30,000	184,000
2,500	17,000	13,000	106,000	32,000	192,000
3,000	22,000	14,000	112,000	34,000	199,000
3,500	27,000	15,000	118,000	36,000	206,000
4,000	32,000	16,000	124,000	38,000	213,000
4,500	37,000	17,000	129,000	40,000	219,000
5,000	42,000	18,000	134,000	42,000	226,000
5,500	47,000	19,000	139,000	44,000	232,000
6,000	52,000	20,000	144,000	46,000	239,000
6,500	56,000	21,000	148,000	48,000	246,000
7,000	61,000	22,000	152,000	50,000	252,000
7,500	65,000	23,000	157,000	52,000	258,000
8,000	69,000	24,000	161,000	54,000	265,000
8,500	73,000	25,000	165,000	56,000	271,000
9,000	77,000	26,000	169,000	58,000	277,000
9,500	81,000	27,000	173,000	60,000	283,000

Belridge Field, Kern County, Calif.

The Belridge field lies between the Lost Hills and McKittrick oil fields, on an anticline extending northwest-southeast. There are two distinct oil zones on this field, but most of the oil to date had come from the upper zone. In fact, so few wells have been drilled to the second zone that practically no production records were available for the preparation of a curve. The curve was prepared from the records of individual wells.

ESTIMATED FUTURE PRODUCTION TABLE—BELRIDGE FIELD

Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
1,000	0	25,000	71,900	58,000	122,100
2,000	4,900	26,000	73,900	60,000	124,500
3,000	9,400	27,000	75,900	62,000	126,900
4,000	13,500	28,000	77,800	64,000	129,200
5,000	17,300	29,000	79,700	66,000	131,500
6,000	21,000	30,000	81,500	68,000	133,700
7,000	24,600	31,000	83,300	70,000	135,900
8,000	28,100	32,000	85,000	72,000	138,100
9,000	31,500	33,000	86,700	74,000	140,300
10,000	34,800	34,000	88,400	76,000	142,500
11,000	38,000	35,000	90,000	78,000	144,700
12,000	41,100	36,000	91,600	80,000	146,900
13,000	44,000	37,000	93,100	85,000	151,900
14,000	46,800	38,000	94,600	90,000	156,700
15,000	49,500	39,000	96,100	95,000	161,300
16,000	52,100	40,000	97,600	100,000	165,700
17,000	54,600	42,000	100,600	105,000	170,000
18,000	56,900	44,000	103,500	110,000	174,200
19,000	59,200	46,000	106,400	115,000	178,400
20,000	61,400	48,000	109,200	120,000	182,500
21,000	63,600.	50,000	111,900	125,000	186,500
22,000	65,800	52,000	114,500	130,000	190,400
23,000	67,900	54,000	117,100	135,000	194,200
24,000	69,900	56,000	119,600	140,000	197,900

Lost Hills Field, Kern County, Calif.

This field is located between the Coalinga and Midway oil fields on the west side of the San Joaquin Valley. The structure is that of an anticline that plunges southeastward. The greater part of the known producing area is underlain by two zones, the top of the first of which is encountered at depths ranging from 400 to 750 feet and the top of the second being encountered in the southern end of the field at depths ranging from 1,500 to 1,900 feet. In the southern end of the field, the interval between the zones appears to be greater than in the northwestern end of the field.

A separate curve was prepared for those wells producing from the second zone, but it was found to be practically identical with that prepared for the whole field, so only the latter is given. This curve was prepared from the record of individual wells.

ESTIMATED FUTURE PRODUCTION TABLE—LOST HILLS FIELD.

Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
1,000	0	21,000	57,800	42,000	99,900
2,000	4,000	22,000	60,100	44,000	103,500
3,000	8,000	23,000	62,400	46,000	107,100
4,000	11,600	24,000	64,600	48,000	110,700
5,000	15,000	25,000	66,800	50,000	114,300
6,000	18,200	26,000	69,000	52,000	117,900
7,000	21,200	27,000	71,100	54,000	121,500
8,000	24,200	28,000	73,200	56,000	125,000
9,000	27,000	29,000	75,200	58,000	128,500
10,000	29,800	30,000	77,200	60,000	131,900
11,000	32,600	31,000	79,200	62,000	135,200
12,000	35,400	32,000	81,200	64,000	138,400
13,000	38,100	33,000	83,200	66,000	141,600
14,000	49,700	34,000	85,200	68,000	144,800
15,000	43,300	35,000	87,100	70,000	148,000
16,000	45,800	36,000	89,000	72,000	151,200
17,000	48,200	37,000	90,000	74,000	154,400
18,000	50,600	38,000	92,700	76,000	157,600
19,000	53,200	39,000	94,500	78,000	160,800
20,000	55,500	40,000	96,300	80,000	164,000

West Side Coalinga Field, Fresno County, Calif.

This field is located on a monocline, the producing strata form one zone, ranging in thickness from 200 to 325 feet, approximately. The records indicate at least three sands in this zone. A fourth has been recognized in a part of the area. The curve shown is designed for all the wells in the West Side field, and was prepared from practically all the available trustworthy data that could be obtained on the output of individual wells. It should be remem-

bered that this curve represents the average future production of the wells of different sizes, and estimates of future production made by using this curve may be slightly in error if the wells for which the estimates are being made are not average wells.

ESTIMATED FUTURE PRODUCTION TABLE—WEST SIDE FIELD, COALINGA.

Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
2,000	0	24,000	107,000	70,000	236,500
3,000	6,000	26,000	115,500	75,000	245,500
4,000	11,500	28,000	124,000	80,000	254,000
5,000	16,000	30,000	132,000	85,000	262,000
6,000	21,000	32,000	140,000	90,000	270,000
7,000	26,000	34,000	147,500	95,000	277,500
8,000	31,000	36,000	155,000	100,000	285,000
9,000	36,000	38,000	162,000	105,000	292,500
10,000	41,000	40,000	168,500	110,000	300,000
11,000	46,000	42,000	174,500	115,000	307,500
12,000	51,000	44,000	180,500	120,000	315,000
13,000	56,000	46,000	186,000	125,000	322,500
14,000	61,000	48,000	191,000	130,000	330,000
15,000	66,000	50,000	196,000	135,000	337,000
16,000	71,000	52,000	201,000	140,000	344,000
17,000	75,500	54,000	205,500	145,000	351,000
18,000	80,000	56,000	210,000	150,000	358,000
19,000	84,500	58,000	214,000	155,000	365,000
20,000	89,000	60,000	218,000	160,000	372,000
22,000	98,000	65,000	227,500		

East Side Coalinga Field, Fresno County, Calif.

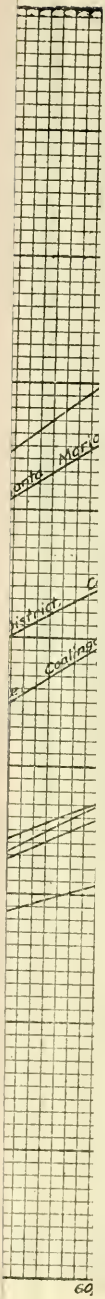
This field is located on an anticline which plunges to the southeastward. Two different zones produce oil on the East Side. The oil from the first zone ranges in gravity from 24 to 28° Baumé, and that from the second zone from 22 to 24° Baumé. The curve shown in the figure is made up from the individual production records of many East Side wells. It may be used for estimating the future production of normal individual wells. A separate curve was

made for the wells in that portion of the field on sections 21, 22, 27, and 28, township 19 south, range 15 east, which produces from both zones but the results were practically identical with those derived from the curve covering all the wells of the East Side

Consequently, but one curve is given. Estimates made from it should be carefully examined and consideration given to the estimate of the future production of unusual wells, of which there are many in this area.

ESTIMATED FUTURE PRODUCTION TABLE—EAST SIDE FIELD, COALINGA.

Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
1,000	0	27,000	107,700	64,000	209,900
2,000	6,500	28,000	110,900	66,000	214,800
3,000	12,000	29,000	114,000	68,000	219,700
4,000	17,200	30,000	117,100	70,000	224,500
5,000	22,200	31,000	120,200	72,000	229,300
6,000	27,000	32,000	123,200	74,000	234,000
7,000	31,700	33,000	126,200	76,000	238,700
8,000	36,200	34,000	129,200	78,000	243,400
9,000	40,600	35,000	132,200	80,000	248,000
10,000	44,800	36,000	135,200	85,000	259,500
11,000	48,900	37,000	138,200	90,000	270,900
12,000	53,000	38,000	141,200	95,000	282,200
13,000	57,000	39,000	144,100	100,000	293,300
14,000	61,000	40,000	147,000	105,000	304,200
15,000	64,900	42,000	152,800	110,000	314,900
16,000	68,800	44,000	158,500	115,000	325,500
17,000	72,600	46,000	164,000	120,000	336,100
18,000	76,200	48,000	169,400	125,000	346,600
19,000	79,800	50,000	174,700	130,000	357,000
20,000	83,400	52,000	179,800	135,000	367,400
21,000	87,000	54,000	184,900	140,000	377,700
22,000	90,500	56,000	190,000	145,000	387,900
23,000	94,000	58,000	195,000	150,000	398,000
24,000	97,500	60,000	200,000	155,000	408,000
25,000	101,000	62,000	205,000	160,000	418,000
26,000	104,400				



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STIMATE

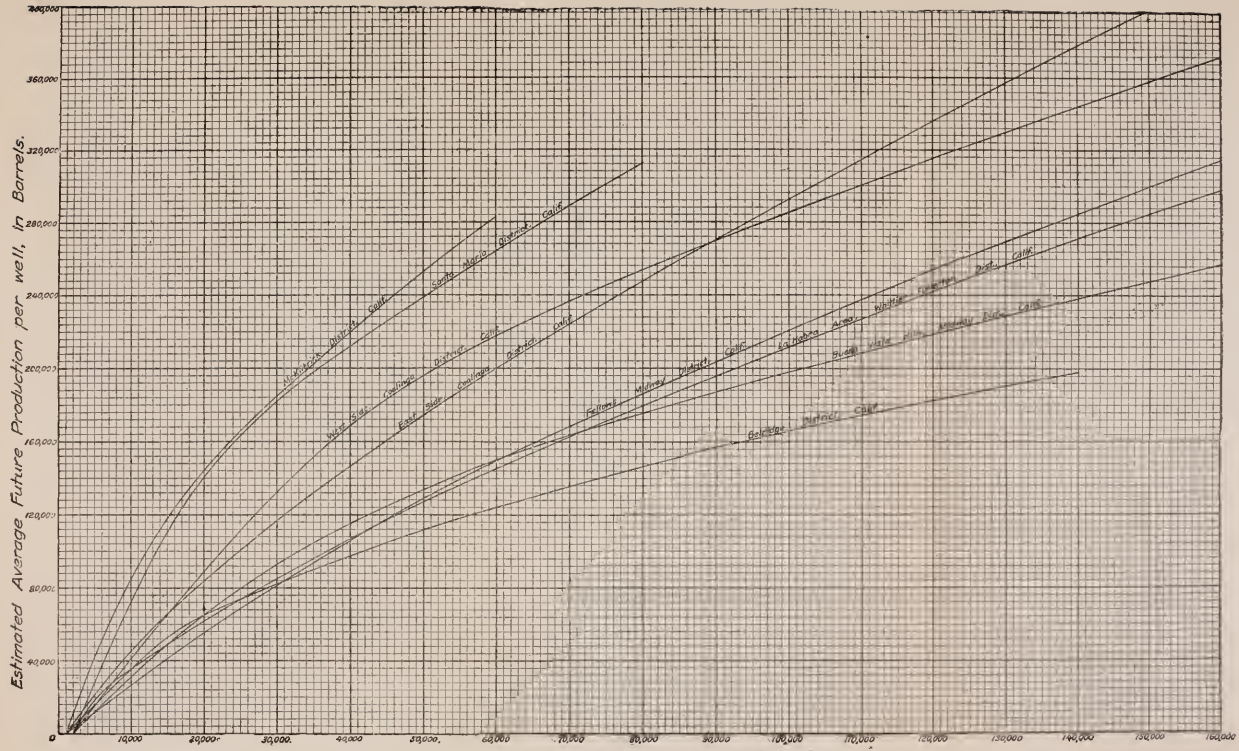

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FIG. 11.—ESTIMATED AVERAGE FUTURE PRODUCTION CURVES, PART OF CALIFORNIA FIELD.

(To face page 159.)

The Kern River Field, Kern County, Calif.

The Kern River field has been one of the most productive per acre in the State. During the year 1918 this field ranked fourth in production.

No records of individual wells were available so the curve presented was made up from the records of the past production of different tracts. The curve is applicable to any tract in the field, but estimates made of future production should be made with a full knowledge of the conditions existing on the lease for which the estimate is desired.

ESTIMATED FUTURE PRODUCTION TABLE—KERN RIVER, OIL FIELD.

Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
1,000	0	7,500	51,000	15,000	76,200
1,200	5,500	8,000	52,700	15,500	77,800
1,400	10,000	8,500	54,400	16,000	79,400
1,600	14,000	9,000	56,100	16,500	81,000
1,800	17,000	9,500	57,800	17,000	82,600
2,000	19,800	10,000	59,500	17,500	84,200
2,500	25,500	10,500	61,200	18,000	85,800
3,000	30,000	11,000	62,900	18,500	87,400
3,500	33,800	11,500	64,600	19,000	89,000
4,000	36,600	12,000	66,300	19,500	90,500
4,500	39,400	12,500	68,000	20,000	92,000
5,000	41,700	13,000	69,700	20,500	93,500
5,500	43,700	13,500	71,400	21,000	95,000
6,000	45,600	14,000	73,000	21,500	96,500
6,500	47,400	14,500	74,600	22,000	98,000
7,000	49,200				

Santa Maria Field, Santa Barbara County, Calif.

The curve for this field was made up from the production records of different tracts producing in the old Santa Maria field. The Lompoc, Cat Canyon, and Casmalia fields were not included. The

The Kern River Field, Kern County, Calif.

The Kern River field has been one of the most productive per acre in the State. During the year 1918 this field ranked fourth in production.

No records of individual wells were available so the curve presented was made up from the records of the past production of different tracts. The curve is applicable to any tract in the field, but estimates made of future production should be made with a full knowledge of the conditions existing on the lease for which the estimate is desired.

ESTIMATED FUTURE PRODUCTION TABLE—KERN RIVER, OIL FIELD.

Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
1,000	0	7,500	51,000	15,000	76,200
1,200	5,500	8,000	52,700	15,500	77,800
1,400	10,000	8,500	54,400	16,000	79,400
1,600	14,000	9,000	56,100	16,500	81,000
1,800	17,000	9,500	57,800	17,000	82,600
2,000	19,800	10,000	59,500	17,500	84,200
2,500	25,500	10,500	61,200	18,000	85,800
3,000	30,000	11,000	62,900	18,500	87,400
3,500	33,800	11,500	64,600	19,000	89,000
4,000	36,600	12,000	66,300	19,500	90,500
4,500	39,400	12,500	68,000	20,000	92,000
5,000	41,700	13,000	69,700	20,500	93,500
5,500	43,700	13,500	71,400	21,000	95,000
6,000	45,600	14,000	73,000	21,500	96,500
6,500	47,400	14,500	74,600	22,000	98,000
7,000	49,200				

Santa Maria Field, Santa Barbara County, Calif.

The curve for this field was made up from the production records of different tracts producing in the old Santa Maria field. The Lompoc, Cat Canyon, and Casmalia fields were not included. The

records used are of tracts wherein the wells produce from the second and third zones. Some of the wells produce from only one zone, but many produce from both.

ESTIMATED FUTURE PRODUCTION TABLE—OLD SANTA MARIA OIL FIELD.

Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
2,000	0	21,000	145,800	42,000	217,400
2,500	4,800	22,000	150,500	44,000	222,800
3,000	9,500	23,000	154,900	46,000	228,200
4,000	18,800	24,000	159,000	48,000	233,600
5,000	27,900	25,000	163,000	50,000	239,000
6,000	37,000	26,000	167,000	52,000	244,200
7,000	46,000	27,000	170,900	54,000	249,400
8,000	54,900	28,000	174,800	56,000	254,600
9,000	63,600	29,000	178,500	58,000	259,800
10,000	72,000	30,000	182,000	60,000	265,000
11,000	80,100	31,000	185,300	62,000	269,800
12,000	88,000	32,000	188,500	64,000	274,600
13,000	95,600	33,000	191,600	66,000	279,400
14,000	102,900	34,000	194,600	68,000	284,200
15,000	110,000	35,000	197,600	70,000	289,000
16,000	116,800	36,000	200,500	72,000	293,500
17,000	123,300	37,000	203,400	74,000	298,000
18,000	129,500	38,000	206,300	76,000	302,500
19,000	134,500	39,000	209,200	78,000	307,000
20,000	140,800	40,000	212,000	80,000	311,500

Ventura County, Calif.

In the region south of the Santa Clara River enough data could be obtained only in one area to prepare an average future production curve. This is the Shields Canyon area, sections 3 and 4, township 3 north, range 19 west. Two sands are productive, but the curve shown is based on the records of individual wells drilled to the upper sand only.

ESTIMATED FUTURE PRODUCTION TABLE—VENTURA FIELD.

Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
500	0	10,500	23,100	21,500	34,800
600	1,300	11,000	23,700	22,000	35,300
800	3,200	11,500	24,300	22,500	35,800
1,000	4,700	12,000	24,900	23,000	36,300
1,200	5,800	12,500	25,500	23,500	36,700
1,500	7,200	13,000	26,100	24,000	37,200
2,000	8,900	13,500	26,700	24,500	37,600
2,500	10,300	14,000	27,300	25,000	38,100
3,000	11,400	14,500	27,800	25,500	38,600
3,500	12,400	15,000	28,300	26,000	39,000
4,000	13,300	15,500	28,800	26,500	39,400
4,500	14,200	16,000	29,300	27,000	39,900
5,000	15,000	16,500	29,800	27,500	40,300
5,500	15,800	17,000	30,300	28,000	40,800
6,000	16,600	17,500	30,800	28,500	41,200
6,500	17,400	18,000	31,300	29,000	41,600
7,000	18,200	18,500	31,800	29,500	42,100
7,500	18,900	19,000	32,300	30,000	42,600
8,000	19,600	19,500	32,800	30,500	43,000
8,500	20,300	20,000	33,300	31,000	43,500
9,000	21,000	20,500	33,800	31,500	43,900
9,500	21,700	21,000	34,300	32,000	44,300
10,000	22,400				

Salt Lake Field, Los Angeles County, Calif.

The Salt Lake field lies between Los Angeles and the Pacific Ocean. The curve shown was prepared from the records of several productive properties in that field instead of from the records of individual wells. The wells in this field produce from the Puente formation, from a zone about 800 feet thick, consisting of the usual alternation of sand, sandy shale and shale.

ESTIMATED FUTURE PRODUCTION TABLE—SALT LAKE FIELD.

Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
1,000	0	28,000	113,000	55,000	156,100
2,000	6,000	29,000	115,000	56,000	157,300
3,000	11,800	30,000	117,000	57,000	158,500
4,000	17,400	31,000	118,800	58,000	159,700
5,000	22,800	32,000	120,600	59,000	160,900
6,000	28,000	33,000	122,400	60,000	162,100
7,000	33,200	34,000	124,200	61,000	163,300
8,000	38,200	35,000	126,000	62,000	164,500
9,000	43,200	36,000	127,800	63,000	165,700
10,000	48,000	37,000	129,600	64,000	166,900
11,000	52,800	38,000	131,400	65,000	168,100
12,000	57,600	39,000	133,200	66,000	169,300
13,000	62,200	40,000	134,800	67,000	170,500
14,000	66,800	41,000	136,400	68,000	171,700
15,000	71,400	42,000	138,000	69,000	172,900
16,000	75,800	43,000	139,600	70,000	174,000
17,000	80,000	44,000	141,100	71,000	175,100
18,000	84,000	45,000	142,600	72,000	176,200
19,000	87,800	46,000	144,100	73,000	177,300
20,000	91,400	47,000	145,600	74,000	178,400
21,000	94,800	48,000	147,000	75,000	179,500
22,000	98,000	49,000	148,400	76,000	180,600
23,000	101,000	50,000	149,800	77,000	181,700
24,000	103,800	51,000	151,100	78,000	182,800
25,000	106,400	52,000	152,400	79,000	183,900
26,000	108,800	53,000	153,700	80,000	185,000
27,000	111,100	54,000	154,900		

Whittier Field, Los Angeles County, Calif.

In this field nearly all the wells produce from the Puente formation on the southwest side of the Puente fault. There are three fairly distinct zones and most of the wells penetrate two. The curve shown in Fig. 12 is based on the action of individual wells in sections 22 and 23 township 2 south, range 11 west. Most of these wells produced from one zone for a number of years and were

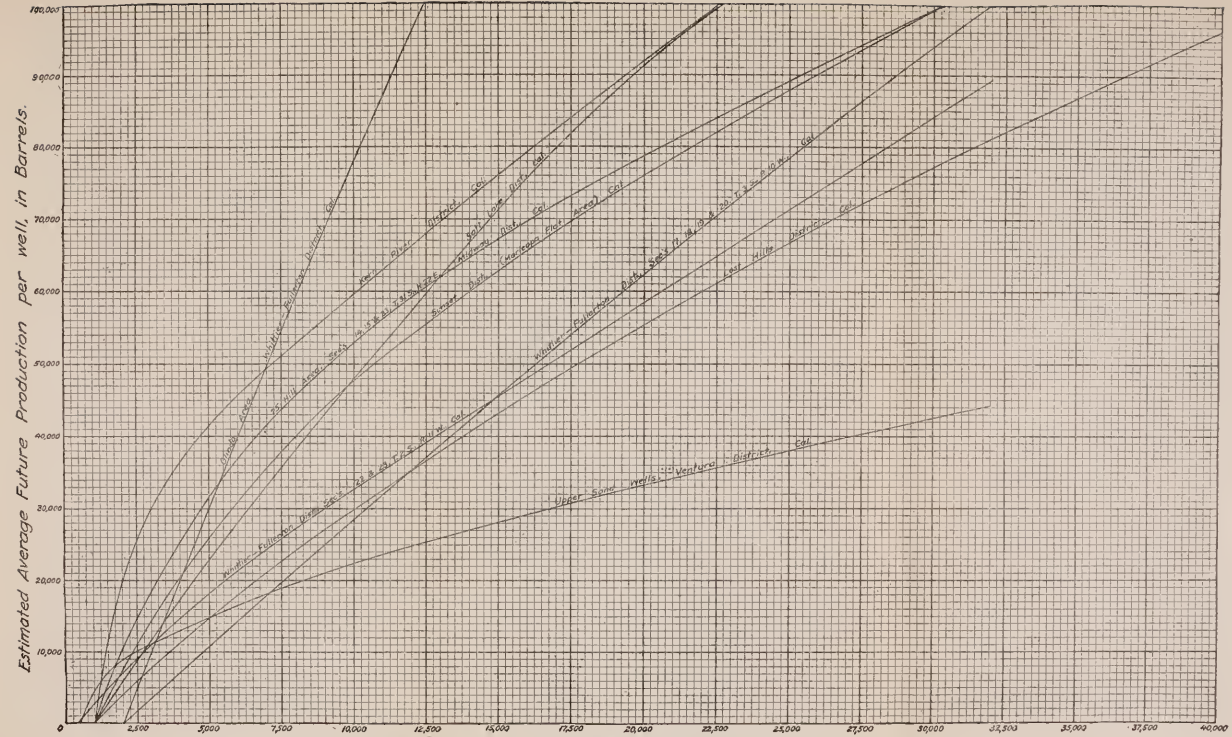


FIG. 12.—ESTIMATED AVERAGE FUTURE PRODUCTION CURVES, PART OF CALIFORNIA FIELD.

(To face page 163.)

deepened in 1915 to 1917 to another zone, which restored them to a condition of flush production. For this reason estimates of future production from this curve should be made with caution.

ESTIMATED FUTURE PRODUCTION TABLE—WHITTIER FIELD.

Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
400	0	10,500	34,100	21,500	62,300
600	1,100	11,000	35,400	22,000	63,600
800	2,100	11,500	36,700	22,500	64,900
1,000	3,000	12,000	37,900	23,000	66,200
1,500	5,300	12,500	39,200	23,500	67,500
2,000	7,300	13,000	40,500	24,000	68,800
2,500	9,200	13,500	41,800	24,500	70,100
3,000	11,200	14,000	43,100	25,000	71,400
3,500	13,100	14,500	44,300	25,500	72,700
4,000	14,800	15,000	45,600	26,000	74,000
4,500	16,500	15,500	46,900	26,500	75,300
5,000	18,200	16,000	48,200	27,000	76,600
5,500	19,800	16,500	49,500	27,500	77,900
6,000	21,300	17,000	50,800	28,000	79,200
6,500	22,800	17,500	52,100	28,500	80,400
7,000	24,300	18,000	53,400	29,000	81,700
7,500	25,800	18,500	54,600	29,500	83,000
8,000	27,200	19,000	55,900	30,000	84,300
8,500	28,600	19,500	57,200	30,500	85,600
9,000	30,000	20,000	58,500	31,000	86,900
9,500	31,300	20,500	59,800	31,500	88,200
10,000	32,700	21,000	61,100	32,000	89,400

West Coyote Field, Los Angeles County, Calif.

The West Coyote field lies a few miles south of the old Whittier field, most of the productive wells having been drilled in sections 17, 18, 19 and 20, township 3 south, range 10 west, and in sections 13 and 24, township 3 south, range 11 west. The curve shown is based on the records of practically all the individual wells in that area.

deepened in 1915 to 1917 to another zone, which restored them to a condition of flush production. For this reason estimates of future production from this curve should be made with caution.

ESTIMATED FUTURE PRODUCTION TABLE—WHITTIER FIELD.

Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
400	0	10,500	34,100	21,500	62,300
600	1,100	11,000	35,400	22,000	63,600
800	2,100	11,500	36,700	22,500	64,900
1,000	3,000	12,000	37,900	23,000	66,200
1,500	5,300	12,500	39,200	23,500	67,500
2,000	7,300	13,000	40,500	24,000	68,800
2,500	9,200	13,500	41,800	24,500	70,100
3,000	11,200	14,000	43,100	25,000	71,400
3,500	13,100	14,500	44,300	25,500	72,700
4,000	14,800	15,000	45,600	26,000	74,000
4,500	16,500	15,500	46,900	26,500	75,300
5,000	18,200	16,000	48,200	27,000	76,600
5,500	19,800	16,500	49,500	27,500	77,900
6,000	21,300	17,000	50,800	28,000	79,200
6,500	22,800	17,500	52,100	28,500	80,400
7,000	24,300	18,000	53,400	29,000	81,700
7,500	25,800	18,500	54,600	29,500	83,000
8,000	27,200	19,000	55,900	30,000	84,300
8,500	28,600	19,500	57,200	30,500	85,600
9,000	30,000	20,000	58,500	31,000	86,900
9,500	31,300	20,500	59,800	31,500	88,200
10,000	32,700	21,000	61,100	32,000	89,400

West Coyote Field, Los Angeles County, Calif.

The West Coyote field lies a few miles south of the old Whittier field, most of the productive wells having been drilled in sections 17, 18, 19 and 20, township 3 south, range 10 west, and in sections 13 and 24, township 3 south, range 11 west. The curve shown is based on the records of practically all the individual wells in that area.

ESTIMATED FUTURE PRODUCTION TABLE, WEST COYOTE FIELD.

Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
2,000	0	66,000	162,800	174,000	249,400
4,000	7,200	68,000	165,200	178,000	252,300
6,000	14,300	70,000	167,500	182,000	255,200
8,000	21,400	72,000	169,800	186,000	258,100
10,000	28,500	74,000	172,000	190,000	261,000
12,000	35,500	76,000	174,100	195,000	264,800
14,000	42,400	78,000	176,100	200,000	268,500
16,000	49,200	80,000	178,000	205,000	272,200
18,000	55,900	82,000	179,800	210,000	275,800
20,000	62,500	86,000	183,200	215,000	279,400
22,000	69,000	90,000	186,500	220,000	283,000
24,000	75,400	94,000	189,700	225,000	286,700
26,000	81,700	98,000	192,900	230,000	290,300
28,000	87,900	102,000	196,000	235,000	293,900
30,000	94,000	106,000	199,000	240,000	297,500
32,000	99,800	110,000	202,000	245,000	301,200
34,000	105,200	114,000	205,000	250,000	304,800
36,000	110,200	118,000	208,000	255,000	308,400
38,000	115,000	122,000	211,000	260,000	312,000
40,000	119,500	126,000	214,000	265,000	315,700
42,000	123,800	130,000	217,000	270,000	319,300
44,000	128,000	134,000	220,000	275,000	322,900
46,000	132,100	138,000	223,000	280,000	326,500
48,000	136,100	142,000	226,000	285,000	330,200
50,000	140,000	146,000	229,000	290,000	334,000
52,000	143,700	150,000	232,000	295,000	337,800
54,000	147,200	154,000	234,900	300,000	341,500
56,000	150,300	158,000	237,800	305,000	345,200
58,000	153,000	162,000	240,700	310,000	348,800
60,000	155,500	166,000	243,600	315,000	352,400
62,000	158,000	170,000	246,500	320,000	356,000
64,000	160,400				

Fullerton Field, Los Angeles County, Calif.

This field is sometimes called the La Habra field, and consists of those wells along the eastward extension of the Coyote hills

near Fullerton. Production is obtained from a fairly well-defined anticline. Figure shows the average future production curve for the average wells of different output in this field. It was prepared from records of individual wells.

ESTIMATED FUTURE PRODUCTION TABLE—FULLERTON OIL FIELD, LA HABRA GROUP.

Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
2,000	0	27,000	78,100	64,000	152,000
2,500	4,500	28,000	80,400	66,000	155,500
3,000	9,000	29,000	82,700	68,000	159,000
4,000	14,500	30,000	85,000	70,000	162,500
5,000	19,500	31,000	87,200	72,000	165,900
6,000	23,500	32,000	89,400	74,000	169,300
7,000	27,000	33,000	91,600	76,000	172,700
8,000	30,000	34,000	93,800	78,000	176,100
9,000	32,800	35,000	96,000	80,000	179,500
10,000	35,500	36,000	98,200	85,000	188,000
11,000	38,200	37,000	100,400	90,000	196,000
12,000	40,900	38,000	102,600	95,000	204,000
13,000	43,600	39,000	104,700	100,000	212,000
14,000	46,300	40,000	106,800	105,000	219,500
15,000	49,000	42,000	111,000	110,000	227,000
16,000	51,500	44,000	115,000	115,000	234,500
17,000	54,000	46,000	119,000	124,000	242,000
18,000	56,500	48,000	123,000	125,000	249,500
19,000	59,000	50,000	127,000	130,000	257,000
20,000	61,500	52,000	130,600	135,000	264,500
21,000	63,900	54,000	134,200	140,000	271,500
22,000	66,300	56,000	137,800	145,000	278,500
23,000	68,700	58,000	141,440	150,000	285,000
24,000	71,100	60,000	145,000	155,000	291,500
25,000	73,500	62,000	148,500	160,000	298,000
26,000	75,800				

Olinda Field, Los Angeles County, Calif.

Fig. 12 shows the average future production curve for the Olinda field. Production in this field comes from the Puente fault zone and the wells as a rule have rather large future productions

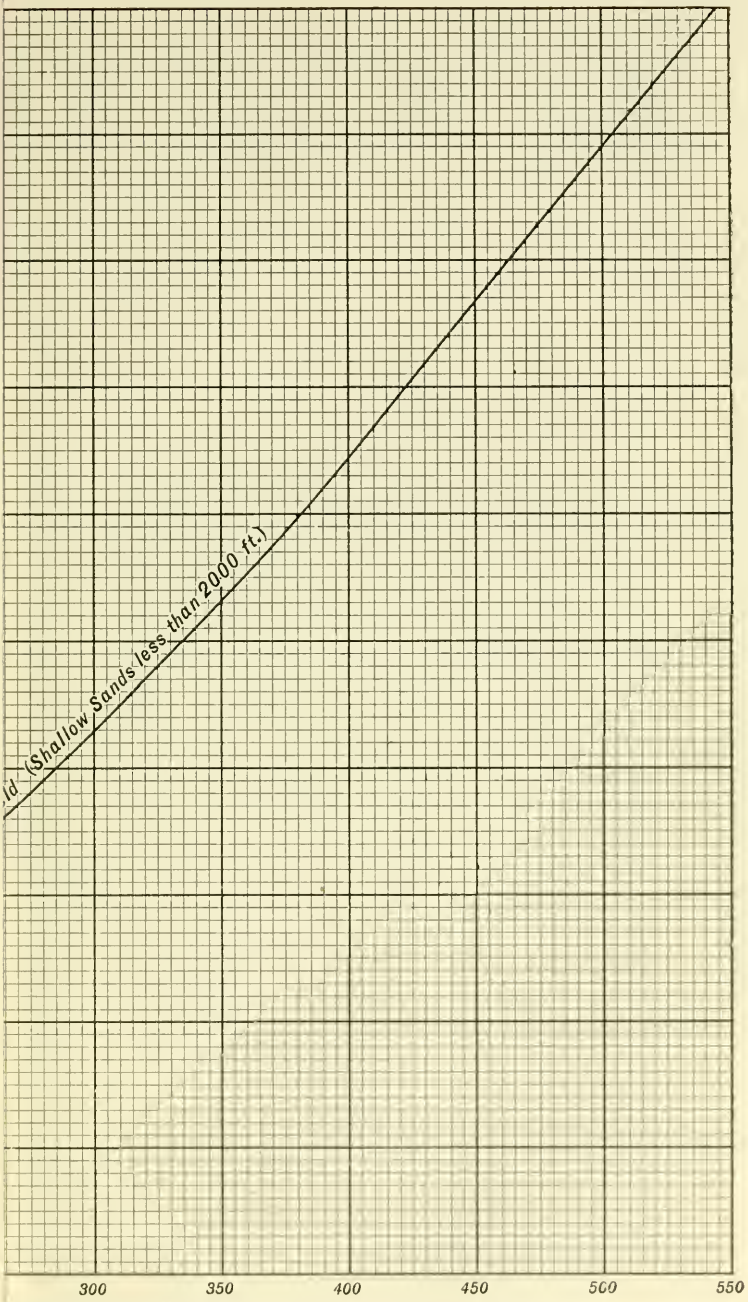
for their size. The curve was compiled from all available records or production of different tracts. The same caution should be used in making estimates of the future production of wells in this field as are used in other fields. Consideration should always be given the local conditions governing production on the tract for which the estimate is to be made.

ESTIMATED FUTURE PRODUCTION TABLE—OLINDA FIELD.

Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well During Taxable Year.	Estimated Average Future Production per Well.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
2,000	0	17,000	141,000	32,000	252,000
3,000	10,000	18,000	150,000	33,000	257,000
4,000	20,000	19,000	158,500	34,000	261,500
5,000	30,000	20,000	167,000	35,000	266,000
6,000	40,000	21,000	175,000	36,000	270,000
7,000	50,000	22,000	183,000	37,000	273,000
8,000	59,500	23,000	191,000	38,000	275,500
9,000	69,000	24,000	198,500	39,000	277,500
10,000	78,000	25,000	206,000	40,000	279,500
11,000	87,000	26,000	213,500	41,000	281,000
12,000	96,000	27,000	221,000	42,000	282,500
13,000	105,000	28,000	228,000	43,000	284,000
14,000	114,000	29,000	235,000	44,000	285,500
15,000	123,000	30,000	241,500	45,000	287,000
16,000	132,000	31,000	247,000		

GULF COAST OF TEXAS AND LOUISIANA.

Curves and tables for the Gulf coast fields of Texas and Louisiana are in preparation.



g Last Four Months of Taxable Year, in Barrels

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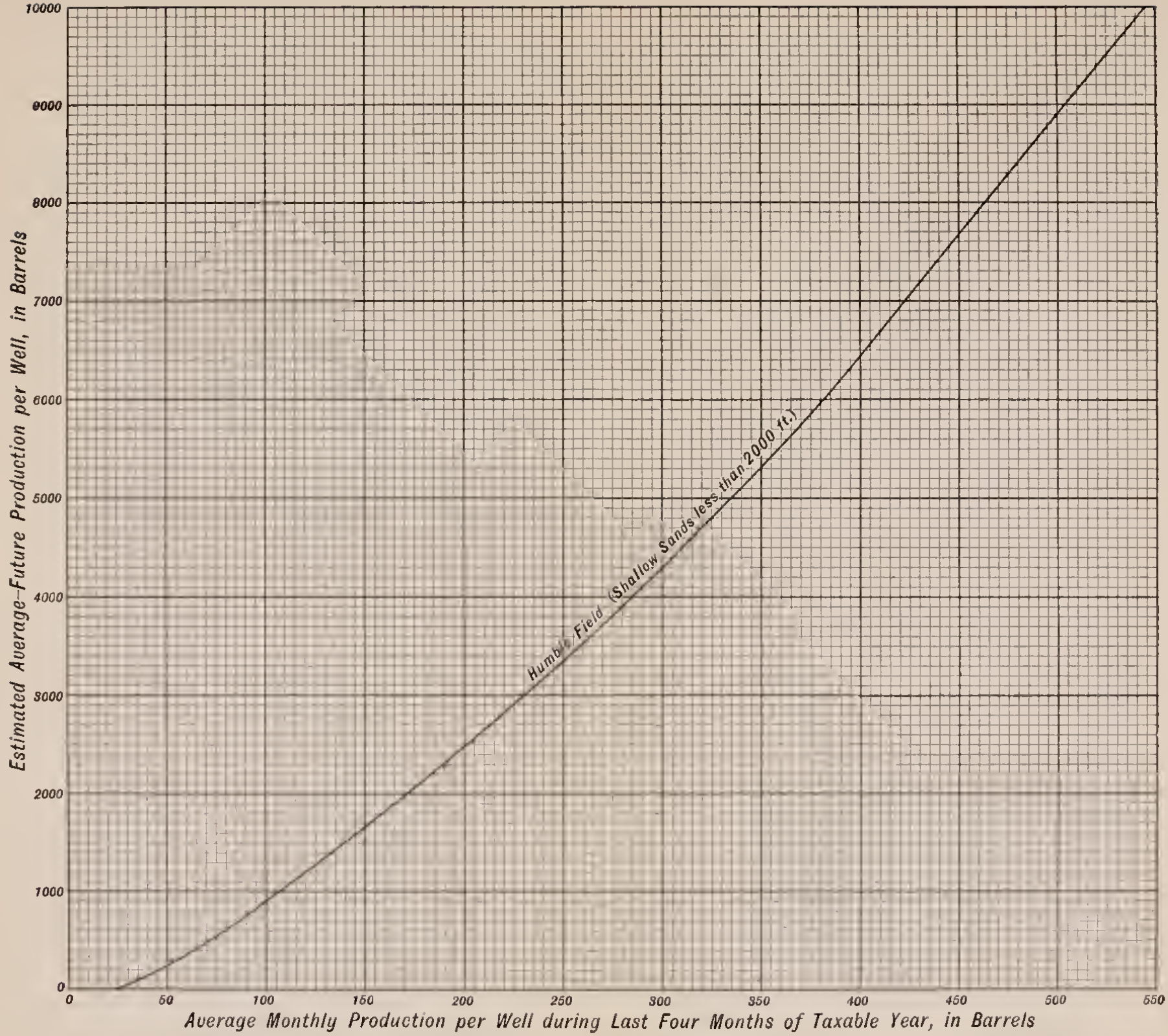

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TABLES FOR THE ESTIMATION OF OIL RESERVES IN THE GULF COAST OIL FIELDS

In issuing the tables included in this paper, it is recognized that many wells or groups of wells may deviate materially from the average given. Owing to high gas pressures and the unconsolidated nature of the sands, wells in the Gulf Coast field come in with a very large production which drops rapidly but irregularly. When production has dropped to a point yielding little profit, wells are commonly reworked, and not infrequently the result is a rejuvenation to another period of practically flush production. In some cases, a single well may go through a series of production declines and revivals. The behavior is so erratic that averages apply only in a broadly general way. In the fields where the gas pressures have been practically exhausted, violent fluctuations of this sort are not so common, but even in these fields the production of individual wells is erratic. The high flush production with rapid decline may cause serious overestimation of reserves if a well comes in, or is cleaned out in the last month of the taxable year.

The tables submitted herewith have been compiled from records of a large number of wells, many of which were being reworked from time to time, and consequently, represent the average well. In the older fields where the gas pressure has been largely exhausted and many of the sands have been flooded, only records of recent years have been used in the compilation.

Curves are not included, as it has been thought best to get these data before the operators at once, rather than to wait for plates to be made. If it is felt by the user that a graphic representation is necessary or desirable, a curve can be constructed in a few moments from the figures given by any engineer. It should be noted also that future production is not based upon average production for taxable year as in the "Manual for the Oil and Gas Industry," but on the average production for the last month of the taxable year.

Humble Field.

The initial production of the pool was from the "cap rock." This is a porous formation, which contained oil under high pres-

TABLES FOR THE ESTIMATION OF OIL RESERVES IN THE GULF COAST OIL FIELDS

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Humble Field.

The initial production of the pool was from the "cap rock." This is a porous formation, which contained oil under high pres-

sures and the early wells were very large producers. The cap rock is now flooded and is not a factor in production.

Numerous irregular lenses of oil sands are found above and overlapping the cap rock. The wells range from 600 to 1,800 feet in depth, and ordinarily do not go to water. The table of shallow sands represents the production from these wells.

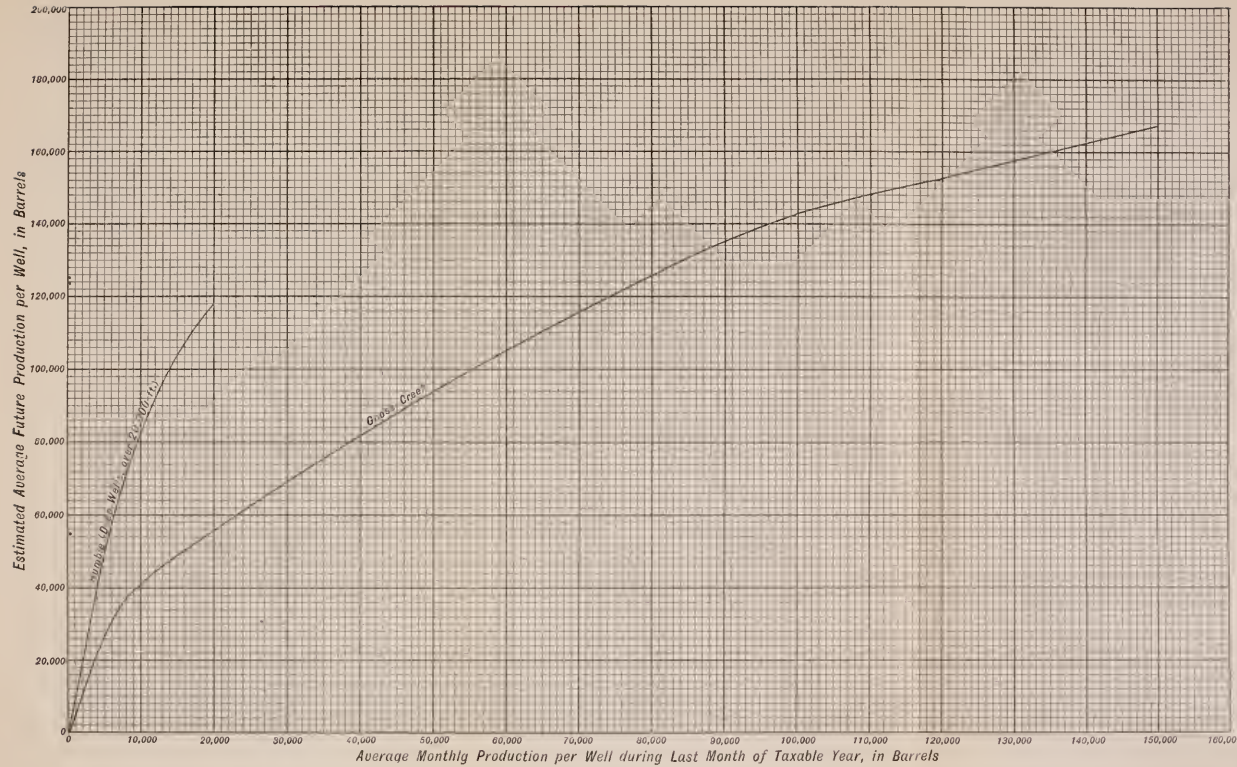
On the edges of the salt dome at a depth of about 3,000 feet, oil sands occur dipping away from the salt dome. These give high

HUMBLE (Shallow Sands, Less than 2,000 Feet).

Average Production per Well per Month Last Four Months Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well per Month Last Four Months. Taxable Year.	Estimated Average Future Production per Well.	Average Production per Well per Month Last Four Months Taxable Year.	Estimateed Average Future Production per Well.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
25	0	175	2,100	400	6,500
50	260	200	2,500	450	7,700
75	550	225	2,800	500	8,900
100	900	250	3,300	550	10,200
125	1,260	300	4,300	600	11,000
150	1,700	350	5,200		

HUMBLE (Deep Wells, over 2,000 Feet).

Average Production per Well Last Month of Taxable Year.	Estimated Future Production.	Average Production per Well Last Month of Taxable Year.	Estimated Future Production.	Average Production per Well Last Month of Taxable. Year.	Estimated Future Production.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
100	0	600	3,823	1,800	16,950
110	100	650	4,240	2,000	19,775
125	147	700	4,660	2,500	26,196
150	223	750	5,235	3,000	31,646
200	355	800	5,676	3,500	36,380
250	760	850	6,124	4,000	40,746
300	1,195	900	6,589	5,000	49,373
350	1,531	1,000	7,599	7,500	68,715
400	2,025	1,200	9,865	10,000	84,046
450	2,425	1,400	12,365	15,000	103,335
500	2,875	1,600	14,576	20,000	117,585
550	3,292				



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gas pressure, large initial production, and die by going to water. The deep sand table of Humble represents production from these sands.

Goose Creek.

Production is from a series of sands or lenses of sand from a depth of 600 feet to 3,600 feet, the large production starting at about 2,200 feet. There are apparently three zones of lenses. If we assume that there is a deep-seated salt dome at Goose Creek, the sands here correspond to those at Humble along the cap rock. The great difference is that the wells die by sanding up or going to water, often very suddenly.

GOOSE CREEK

Average Production per Well Last Month of Taxable Year.	Estimated Future Production.	Average Production per Well Last Month of Taxable Year.	Estimated Future Production.	Average Production per Well Last Month of Taxable Year.	Estimated Future Production.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
300	0	1,700	7,400	20,000	54,400
350	460	2,000	9,260	25,000	62,000
400	730	2,300	11,260	30,000	68,200
450	1,010	2,500	12,800	35,000	74,400
500	1,230	2,700	14,330	40,000	80,200
600	1,590	3,000	16,400	45,000	85,500
700	1,900	3,500	19,640	50,000	92,000
800	2,250	4,000	22,560	60,000	104,000
900	2,730	5,000	27,200	70,000	115,500
1,000	3,330	6,000	31,000	80,000	127,500
1,100	3,630	8,000	37,500	85,000	133,000
1,300	4,730	10,000	31,000	150,000	167,000
1,500	6,030	15,000	47,000		

Saratoga.

In Saratoga pool the sands are very irregular and cannot be correlated from well to well. Apparently, a series of limestones, sands and clays has been contorted by the formation of a salt dome. Most of the wells eventually go to water, but in some lenses of sand water does not appear. In spite of the fact that wells are

gas pressure, large initial production, and die by going to water. The deep sand table of Humble represents production from these sands.

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Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
300	0	1,700	7,400	20,000	54,400
350	460	2,000	9,260	25,000	62,000
400	730	2,300	11,260	30,000	68,200
450	1,010	2,500	12,800	35,000	74,400
500	1,230	2,700	14,330	40,000	80,200
600	1,590	3,000	16,400	45,000	85,500
700	1,900	3,500	19,640	50,000	92,000
800	2,250	4,000	22,560	60,000	104,000
900	2,730	5,000	27,200	70,000	115,500
1,000	3,330	6,000	31,000	80,000	127,500
1,100	3,630	8,000	37,500	85,000	133,000
1,300	4,730	10,000	31,000	150,000	167,000
1,500	6,030	15,000	47,000		

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constantly being reworked, the decline *on the average* is fairly regular, and some wells have produced since 1905.

Two tables are presented—one for the Rio Bravo holdings where the wells have been reasonably spaced and the other for the rest of the pool, where town lot drilling was the rule.

SARATOGA, RIO BRAVO.

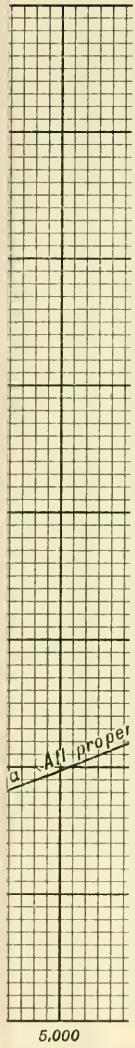
Average Production per Well During Taxable Year.	Estimated Future Production.	Average Production per Well During Taxable Year.	Estimated Future Future	Average Production per Well During Taxable Year.	Estimated Future Production.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
500	0	3,000	10,500	10,000	43,000
585	300	3,500	13,900	12,000	50,000
800	885	4,000	17,300	15,000	61,100
1,100	1,685	5,000	22,500	17,500	69,400
1,250	2,000	6,000	27,300	20,000	77,100
1,500	2,900	7,000	31,400	22,500	84,150
2,000	4,800	8,000	35,400	25,000	91,000
2,500	7,600	9,000	39,460	26,000	93,700

SARATOGA (All Properties Except Rio Bravo).

Average Monthly Production per Well During Taxable Year.	Estimated Future Product on.	Average Monthly Production per Well During Raxable Year.	Estimated Future Production.	Average Monthly Production per Well During Taxable Year.	Estimated Future Production.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
330	0	1,800	2,280	6,000	9,500
500	150	2,000	2,750	7,000	11,290
700	330	2,500	4,080	8,000	12,900
900	580	3,000	4,910	9,000	15,000
1,000	710	3,500	5,740	10,000	17,550
1,250	1,030	4,000	6,580	11,000	21,350
1,500	1,600	5,000	8,080	12,000	27,130

Sour Lake.

Conditions are similar to those in Saratoga. Production is now from sands along the cap rock from a depth of 500 to 1,500 feet.



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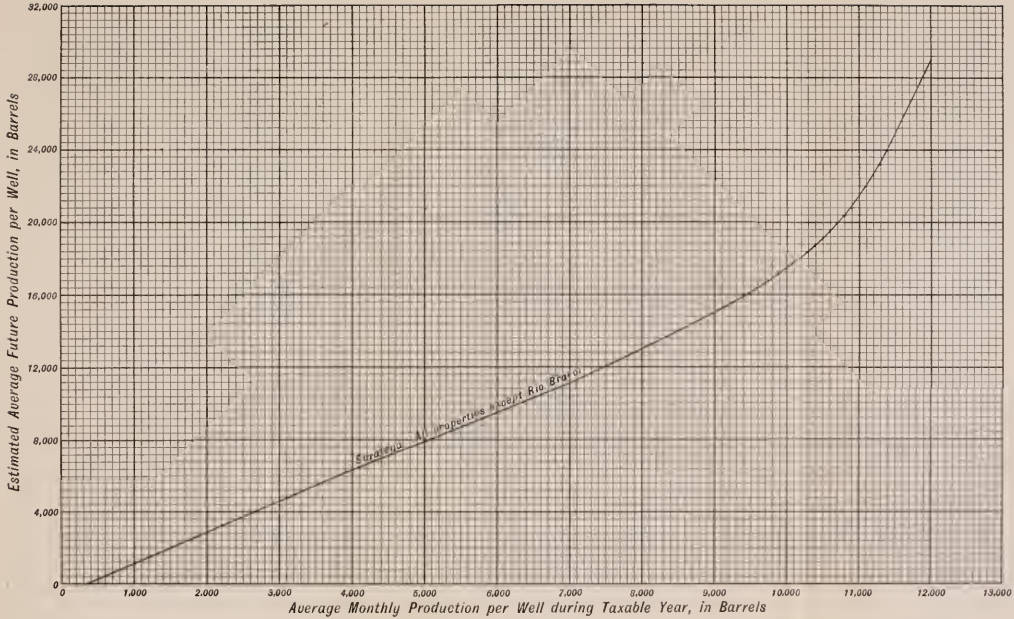

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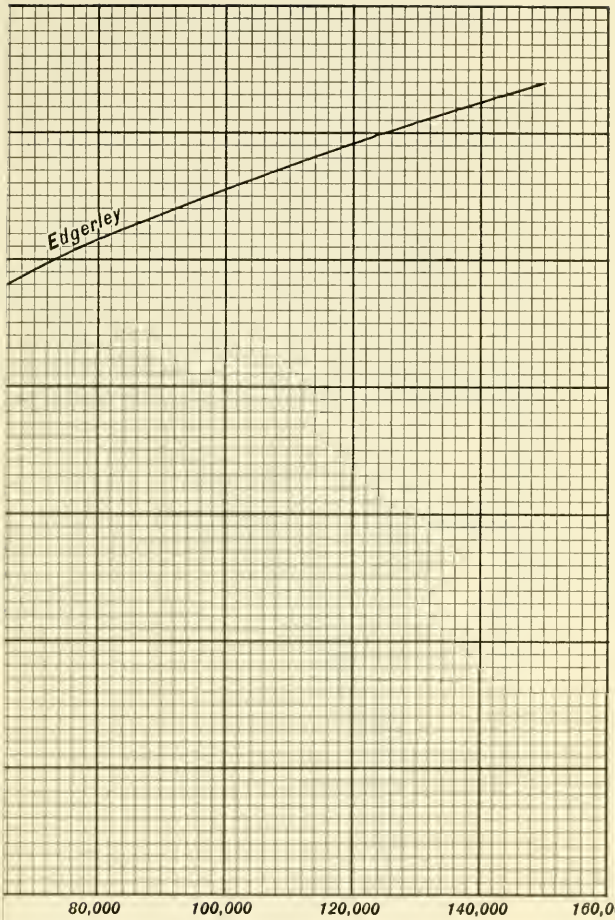

Well during Taxable Year, in Barrels

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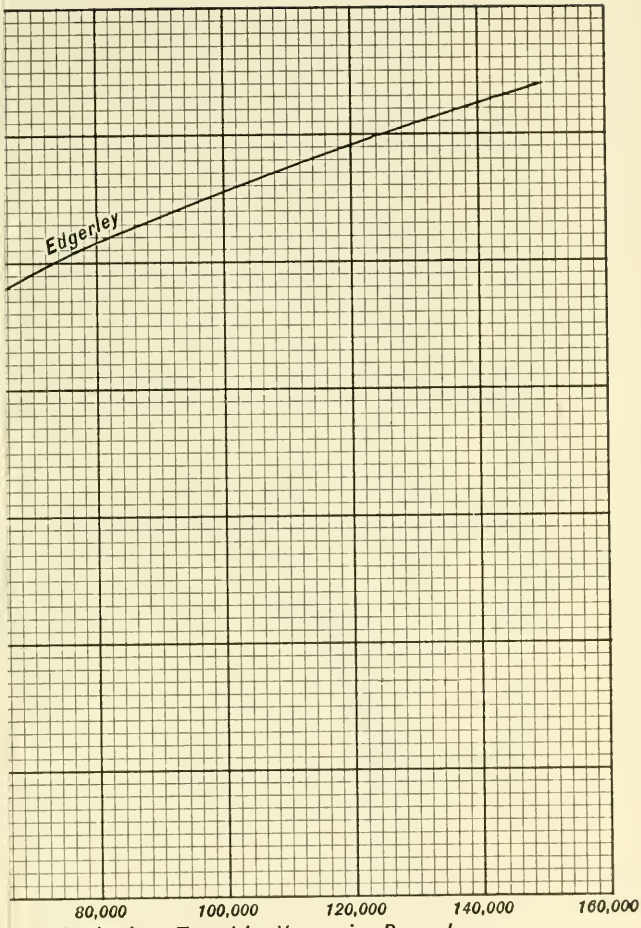

Well during Taxable Year, in Barrels

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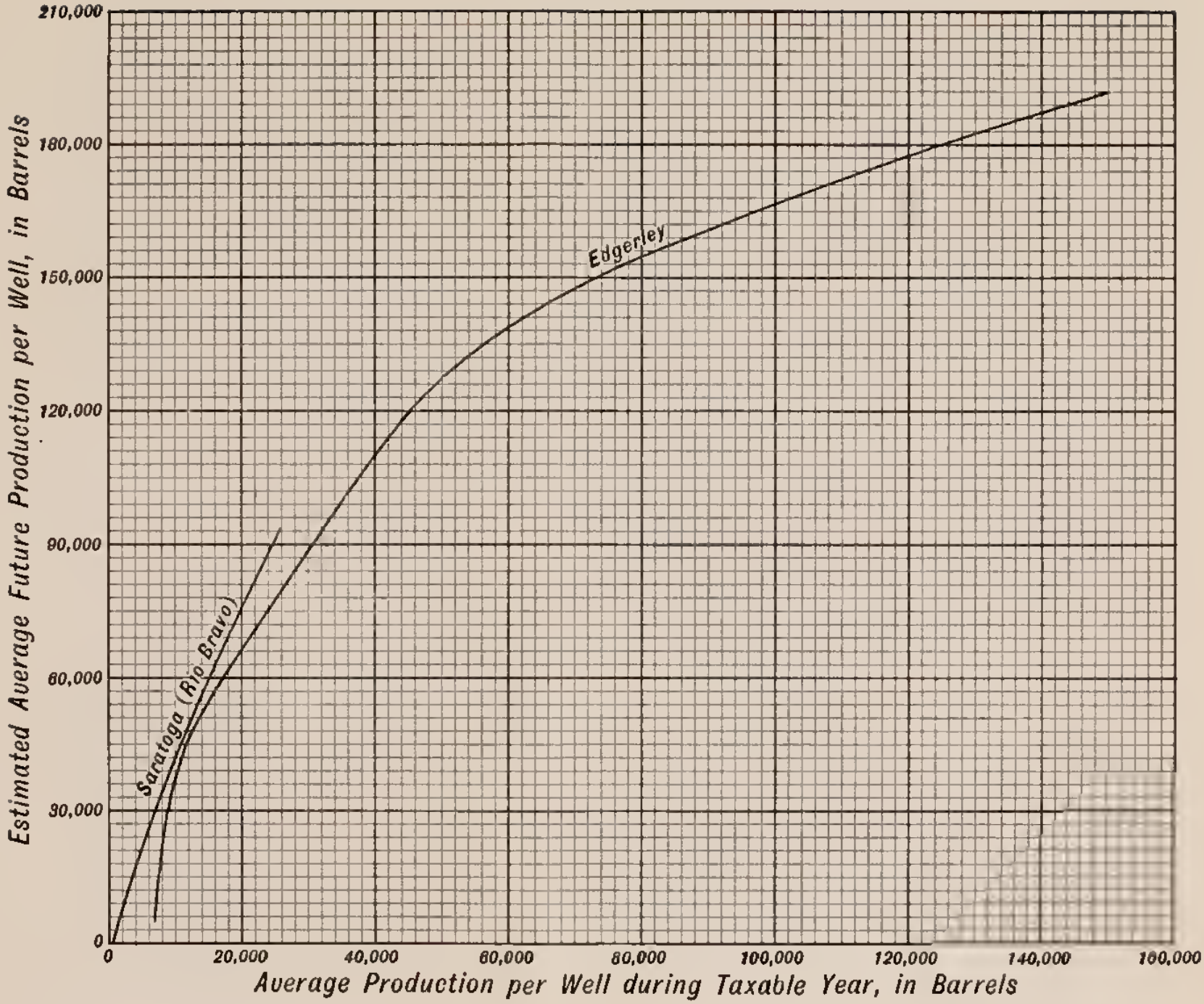

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SOUR LAKE.

Average Production per Well Last Month of Taxable Year.	Estimated Future Production.	Average Production per Well Last Month of Taxable Year.	Estimated Future Production.	Average Production per Well Last Month of Taxable Year.	Estimated Future Production.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
41	50	600	10,000	2,000	27,840
50	185	700	11,750	2,500	20,700
75	765	800	13,550	3,000	32,900
100	1,600	900	15,280	4,000	37,200
150	2,800	1,000	16,870	5,000	41,000
175	3,200	1,100	17,870	6,500	46,300
200	3,750	1,200	20,100	7,000	47,600
250	4,500	1,300	21,400	8,000	51,500
300	5,300	1,400	22,600	9,000	56,000
350	6,000	1,500	23,900	10,000	61,000
400	6,800	1,700	25,540	11,000	66,000
500	8,375	1,900	27,240	12,000	71,000

Batson.

Produces from irregular sands as in Saratoga and Sour Lake from depths of 200 to 1,500 feet. Wells constantly reworked but some wells producing in 1908 are still productive in 1918.

BATSON.

Average Production per Well Last Month of Taxable Year.	Estimated Future Production	Average Production per Well Last Month of Taxable Year.	Estimated Future Production	Average Production per Well Last Month of Taxable Year.	Estimated Future Production
Barrels.	Barrels.	Barrels.	Barrels.	Barrels	Barrels.
20	0	250	7,680	1,500	23,000
25	40	300	9,180	1,750	24,300
50	380	400	12,260	2,000	25,400
75	890	500	13,960	2,500	27,000
100	1,630	750	17,000	3,000	27,900
150	3,760	1,000	19,400	4,000	29,100
200	5,830	1,250	20,400	5,000	30,700

SOUR LAKE.

Average Production per Well Last Month of Taxable Year.	Estimated Future Production.	Average Production per Well Last Month of Taxable Year.	Estimated Future Production.	Average Production per Well Last Month of Taxable Year.	Estimated Future Production.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
41	50	600	10,000	2,000	27,840
50	185	700	11,750	2,500	20,700
75	765	800	13,550	3,000	32,900
100	1,600	900	15,280	4,000	37,200
150	2,800	1,000	16,870	5,000	41,000
175	3,200	1,100	17,870	6,500	46,300
200	3,750	1,200	20,100	7,000	47,600
250	4,500	1,300	21,400	8,000	51,500
300	5,300	1,400	22,600	9,000	56,000
350	6,000	1,500	23,900	10,000	61,000
400	6,800	1,700	25,540	11,000	66,000
500	8,375	1,900	27,240	12,000	71,000

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Barrels.	Barrels.	Barrels.	Barrels.	Barrels	Barrels.
20	0	250	7,680	1,500	23,000
25	40	300	9,180	1,750	24,300
50	380	400	12,260	2,000	25,400
75	890	500	13,960	2,500	27,000
100	1,630	750	17,000	3,000	27,900
150	3,760	1,000	19,400	4,000	29,100
200	5,830	1,250	20,400	5,000	30,700

Edgerly, Vinton and Evangeline.

These are typical salt-dome pools which have been exhausted except for the stray sands and an occasional pocket of oil in the cap rock. Production is extremely erratic and the deviation from the averages given in the table is large.

EDGERLEY.

Average Production per Well During Taxable Year.	Estimated Future Production.	Average Production per Well During Taxable Year.	Estimated Future Production.	Average Production per Well During Taxable Year.	Estimated Future Production.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
7,000	4,000	15,000	56,800	60,000	140,100
7,250	6,000	20,000	65,300	75,000	151,300
7,500	10,000	25,000	74,000	90,000	160,950
8,000	20,120	30,000	87,200	100,000	166,500
9,000	34,700	35,000	99,500	120,000	177,100
10,000	44,000	40,000	110,800	135,000	185,200
11,000	48,240	50,000	129,100	150,000	192,140

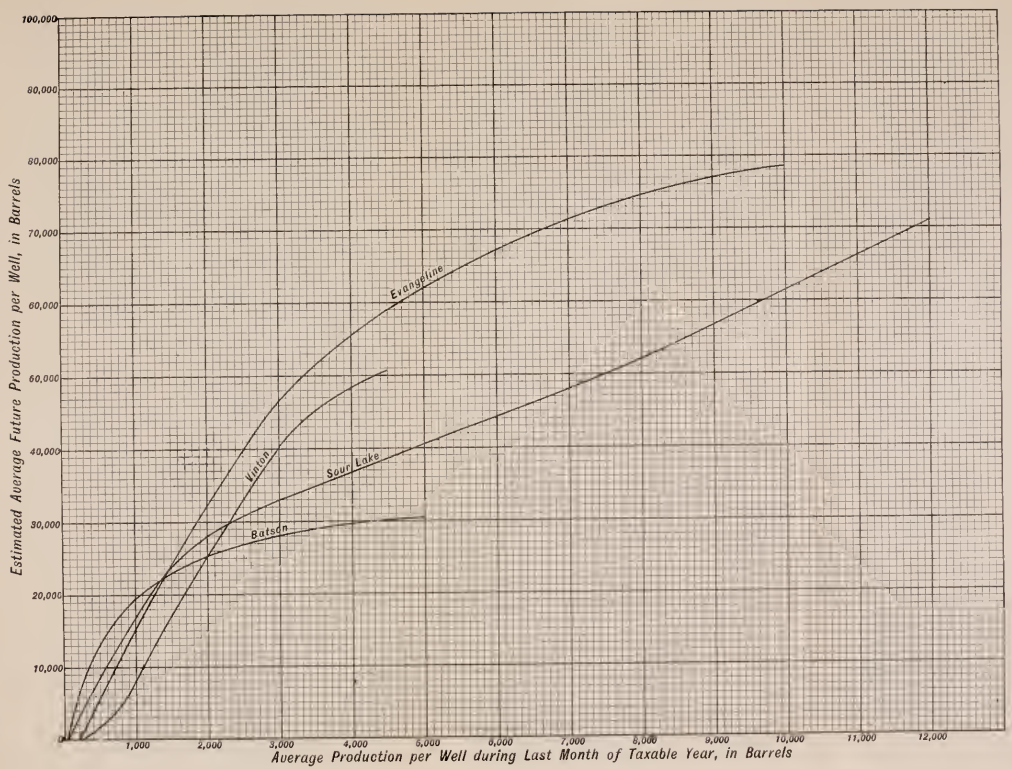
VINTON.

Average Production per Well Last Month of Taxable Year.	Estimated Future Production.	Average Production per Well Last Month of Taxable Year.	Estimated Future Production.	Average Production per Well Last Month of Taxable Year.	Estimated Future Production.
Barrels	Barrels.	Barrels.	Barrels.	Barrels.	Barrels
250	0	1,000	8,500	2,250	28,100
300	250	1,100	10,800	2,500	32,650
400	860	1,200	12,400	2,750	37,000
500	1,780	1,350	14,600	3,000	40,600
600	2,800	1,500	17,400	3,500	43,800
700	4,025	1,750	20,400	4,000	47,600
800	5,700	2,000	23,900	4,500	51,150
900	7,000				

For Spindle Top, Anse Le Butte and Welch, the use of the Evangeline table is suggested.

For Damon Mound and Big Hill, Hull, the use of the Goose Creek table is suggested.

ngeline
5,000
er Well



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For Markham, the use of the Humble Shallow sand table is suggested.

Sufficient data for the compilation of a table are lacking in these fields.

In any case where the production for one well per month is above that given in the table, use the Goose Creek Table.

EVANGELINE.

Average Production per Well Last Month of Taxable Year.	Estimated Future Production.	Average Production per Well Last Month of Taxable Year.	Estimated Future Production.	Average Production per Well Last Month of Taxable Year.	Estimated Future Production.
Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
160	0	700	10,020	2,000	31,500
200	340	800	12,900	2,500	40,000
250	980	900	13,900	3,000	47,000
300	1,400	1,000	15,900	4,000	56,200
350	2,400	1,100	17,580	5,000	62,100
400	3,200	1,200	19,000	6,000	67,100
450	4,370	1,300	21,080	7,000	71,100
500	5,630	1,400	22,380	8,000	74,600
550	6,570	1,500	25,200	9,000	77,100
600	7,700	1,750	27,700	10,000	78,770
650	9,930				

MEXICAN OIL FIELDS.

General features.—The known oil fields of Mexico are included within two great regions, both of which are segments of the Gulf Coastal Plane, Tampico-Tuxpam, and Tehuantepec-Tabasco regions. They cover approximately 20,000 to 30,000 square miles and include some 20 local fields. A very rough estimate places the proved area in the two regions at 25 square miles, the prospective area at 500 to 1,000 square miles. Inasmuch as less than 1,000 wells have been drilled for oil in the entire Republic up to the present time, and as a great bulk of the oil has come from two wells, it would be rash indeed to give too much weight to estimates of unit areas.

The principal oil-yielding rocks are limestones or limy shales of Cretaceous or Eocene age. Some oil is found in the later Tertiaries in the southern region. Fields are generally anticlinal in struc-

For Markham, the use of the Humble Shallow sand table is suggested.

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Barrels.	Barrels.	Barrels.	Barrels.	Barrels.	Barrels.
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200	340	800	12,900	2,500	40,000
250	980	900	13,900	3,000	47,000
300	1,400	1,000	15,900	4,000	56,200
350	2,400	1,100	17,580	5,000	62,100
400	3,200	1,200	19,000	6,000	67,100
450	4,370	1,300	21,080	7,000	71,100
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The principal oil-yielding rocks are limestones or limy shales of Cretaceous or Eocene age. Some oil is found in the later Tertiaries in the southern region. Fields are generally anticlinal in struc-

ture, but in some instances the structure has not yet been determined. The underground reservoirs are associated with volcanic intrusions.

The oldest development of importance began in 1906, but the larger wells were not developed until four or five years later. The wells average in depth 2,500 feet and in production from 50 to over 100,000 barrels daily. The oils range in gravity from 10° to 14° Baumé in the Panuco field and from 15° to 29° Baumé in the others, the average for the most productive field, the Tepetate, being about 21° or .927 specific gravity. The oil is usually accompanied by large quantities of wet gas. Estimates of from 4,000,000 to 12,000,000 cubic feet of gas daily being yielded by some of the wells. Both the rotary hydraulic and standard cable systems of drilling are used.

The first and most general use for the Mexican crude oil aside for supplying oil for refining for local trade has been as fuel oil. Most of the oil is exported to the United States or other countries.

Statement regarding depletion allowances.—The depletion of the oil reserves in the Mexican fields is an unquestionable fact, but owing to the large volume of oil produced by the commercially successful wells and to restricted transportation facilities, it is at present and has been during past years, impossible to show the actual diminution of flow. In other words, the existing pipe-line systems in connection with the available tank steamer fleets can not transport the oil out of Mexico as fast as the wells are capable of producing it. Obviously, at some future time the diminution in the oil flow or the increase in transportation or storage capacities will reach a point where the decline in production of the large wells is actually shown, but for present purposes in estimating allowances for depletion there is little or nothing in the shape of production decline records on which to base an estimate of the probable future production of the large Mexican oil wells and one is therefore confronted at the outset by an almost complete lack of records essential in computing the fundamental unknown factors in the problem. Were one to compute at present the depletion of the large Mexican oil wells, which yield the bulk of the marketed oil, on the basis of the diminution of flow, he would arrive in most cases at the incongruous conclusion that no depletion takes place even though the well might be producing millions of barrels per year.

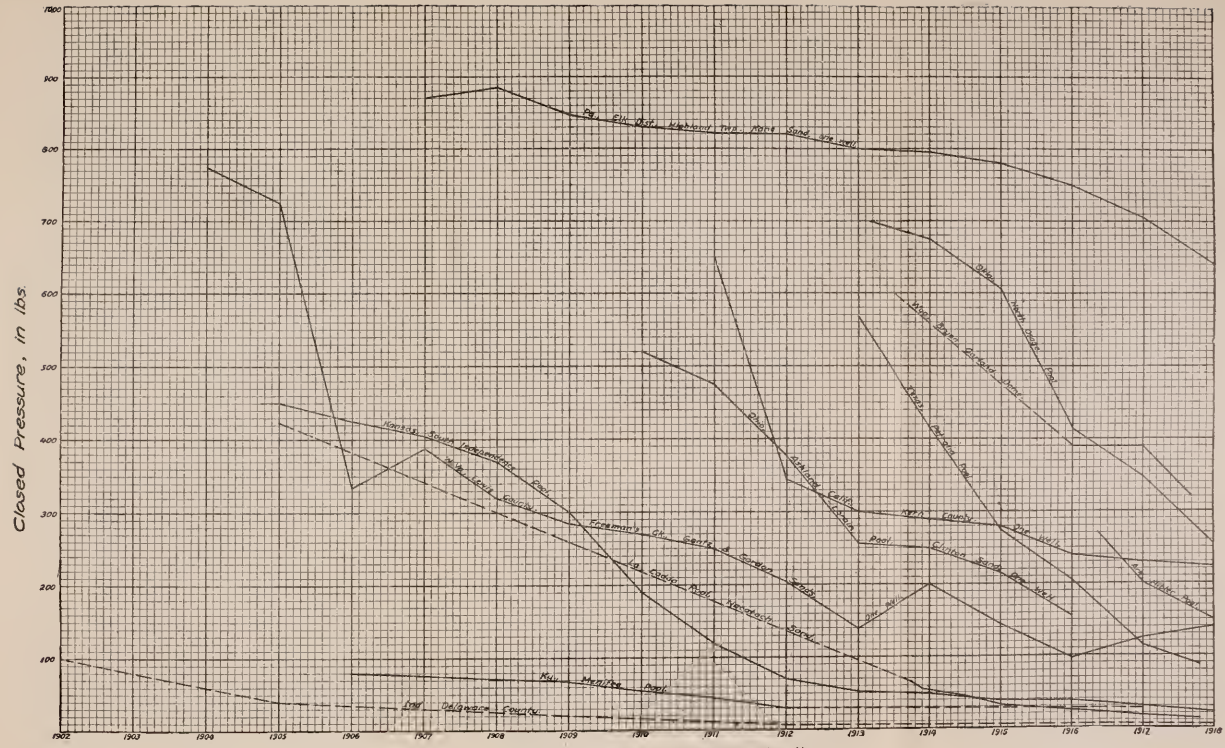

FIG. 13.—REPRESENTATIVE CLOSED PRESSURE DECLINE CURVES FOR GAS WELLS AND POOLS IN VARIOUS PARTS OF THE UNITED STATES. SEE PAGES 31 AND 125.

(To face page 175.)

With this in mind we must be sure at the outset that (any estimates of probable depletion of the content of Mexican oil land, being based almost entirely on more or less plausible conjectures) any estimates of depletion of necessity presuppose a previous knowledge of the probable amount of oil underground in any particular property, and although here again we are confronted with the lack of sufficient data on which to base accurate conclusions, enough evidence is available to enable one in most instances to roughly approximate the oil reserves. The greatest elasticity, however, will be given to the taxpayer in devising methods of estimating reserves so that proper allowances may be made in practically every individual case that comes up for consideration, in order not to work undue hardship on the operators by arbitrary interpretations.

The producing life of gushers yielding thousands of barrels of oil daily, obviously is controlled by different factors from those governing the small pumping wells perhaps adjoining a big producer, and these and many other factors affecting the problem are rendered doubly obscure by the indefinite length of time throughout which the effect of the restricted land and marine transportation facilities will be felt.

In view of the foregoing, the task of estimating the amount of oil in any particular property will be left largely to the taxpayer controlling the tract and the Internal Revenue Bureau will for the present confine itself to a critical analysis of the various estimates before issuing any average curves or approximate bench marks on which to base the computation of depletion allowances.

In setting up values as of March 1, 1913, or for any subsequent date, for properties in Mexico or any other foreign country, or in computing depletion and depreciation allowances, the same evidence will be required by the Internal Revenue Bureau as that for properties in the United States, and in filing returns the taxpayer must in all cases append complete evidence supporting all claims.

GAS FIELDS OF THE UNITED STATES.

Representative decline curves.—On Fig. 13 are shown selected closed-pressure decline curves for wells, pools, and sands in various parts of the United States. It will be observed first, that the rate of decline varies between wide limits; second, that there are

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Representative decline curves.—On Fig. 13 are shown selected closed-pressure decline curves for wells, pools, and sands in various parts of the United States. It will be observed first, that the rate of decline varies between wide limits; second, that there are

occasional temporary rises in pressure; third, that a well or pool may on the one hand " drown out " abruptly, the pressure declining from perhaps several hundred pounds to zero in a few days as the well fills with water, or at the other extreme a well or pool such as the low-pressure wells of Indiana or certain high-pressure wells of Pennsylvania may decline very slowly over a period of many years.

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